APPENDIX C AESO CONGESTION ASSESSMENT

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1 Introduction[1]

This Congestion Assessment Report is a supplement to the Central East Transfer-out (CETO) Transmission Development Planning Report (Planning Report)[2]. This congestion assessment report documents the methods of analysis, modeling assumptions, and results of a congestion assessment that was conducted for CETO.

Congestion is identified to occur when the transmission system cannot accommodate in-merit generation because the resulting power flows would contravene reliability standards (such as thermal loading criteria) and/or ISO rules, and mitigations that affect the energy market are consequently needed.

The congestion assessment focused on the Study Area defined in the Planning Report. The congestion assessment estimated the percentage of time that congestion would occur in the Study Area. The congestion assessment considered the addition of generation to the Study Area, using two scenarios in which the existence and operating patterns of thermal generators were varied, and established the relationship between renewable generator output in the Study Area and the likelihood of congestion.

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The purpose of the congestion assessment was to:

- estimate the probability of congestion arising in the Study Area as new generation develops; and
- inform the establishment of construction milestone for the AESO's Preferred Transmission Development[3].

2 Methods

The probability that congestion will occur was estimated using an integrated system model that represents the transmission network and the production costs of generators. A computer program called Aurora[4] was used for the assessment. Aurora determines hourly generator dispatches using load and generator production cost data; and calculates the power flows that result from each dispatch using a direct current (DC) network model. The calculated power flows were used to identify hours in which one

[1] In this congestion assessment report, the pre-Development transmission system will be referred to as pre-CETO, and the Stage 1 and Stage 2 post-Development transmission system will be referred to as post-CETO First Circuit, and post-CETO Second Circuit.

[2] Filed under separate cover.

[3] The Preferred Transmission Development is defined in the Planning Report.

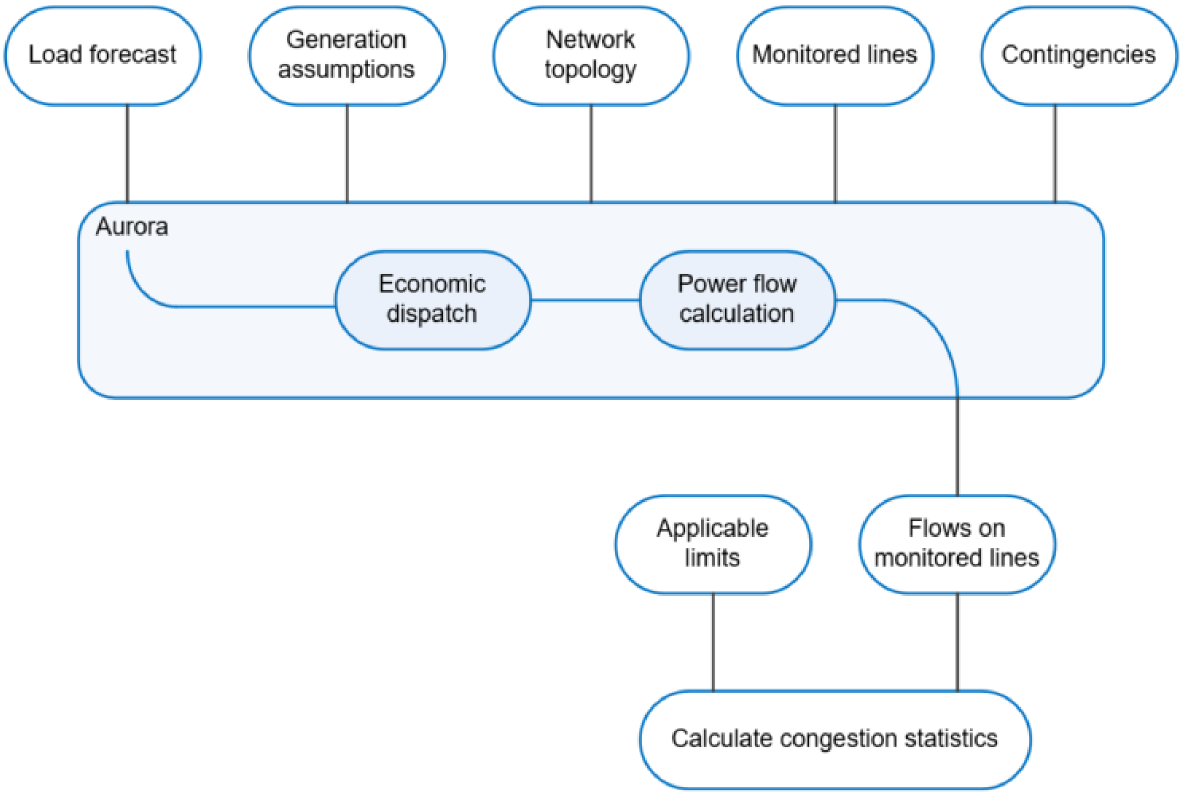
[4] Aurora is energy forecasting software published by Energy Exemplar. For more information please refer to their website: https://energyexemplar.com/solutions/aurora/

or more transmission lines would have, or been at risk of having, loading above applicable limits[5]. Three types of congestion assessment were performed. They are described in the following sub-sections.

The Planning Report was consulted when determining the transmission lines that would be monitored and the contingencies that would be examined in the congestion assessment.

Figure 1 shows the inputs and process involved in this congestion assessment.

Figure 1 – Congestion Assessment Process



Results were calculated for two scenarios and a common study period as explained in Section 3. For each scenario, a set of system states[6] were simulated for each hour in the study period[7]. Each state was

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[5] The limits that apply depend on the specific method of assessment. The following sub-sections discuss the methods of assessment and which limits were applicable, and Section 3.1.4 provides numerical values for applicable limits.

classified as congested or un-congested. The relationship between the percentage of hours that were classified as congested and the amount of new generation added to the Study Area is the main result of this assessment.

[6] A system state is a description of the interconnected electric system, including the load, generator dispatch, transmission network topology, and the status of system elements.

[7] Each hour was represented by several states, instead of just one, so that variations in wind, temperature, and load could be reflected in the study results.

2.1 Congestion Assessment under Category A

Two measures of congestion were calculated in connection with Category A conditions:

a) Category A congestion

b) Category A-MSSC congestion

The system states under consideration have all system elements in service in Category A conditions.

The two measures above relate to the AESO's obligations under Section 15(1)(e)(i) of the *Transmission Regulation,* which requires that the AESO:

> *taking into consideration the characteristics and expected availability of generating units, plan a transmission system that*
>
> > *(i) is sufficiently robust so that 100% of the time, transmission of all anticipated in-merit electric energy referred to in section 17(c) of the Act can occur when all transmission facilities are in service [...]*

The two measures of Category A congestion are discussed in Sections 2.1.1 and 2.1.2.

2.1.1 Category A Congestion

When "Category A" congestion was assessed:

a) all system elements were in service;

b) generation dispatch was determined as if the system had no transmission constraints;

c) the hypothetical effects of contingency events, including post-contingency transmission line loading, were not considered; and

d) a transmission system state was classified as congested whenever any monitored transmission line in the Study Area had loading above its seasonal normal rating.

2.1.2 Category A-MSSC Congestion

When Category A-MSSC congestion was assessed:

a) all system elements were in service;

b) generation dispatch was determined as if the system had no transmission constraints;

c) the effects of contingency events played a role when system states were classified as congested, with further explanation to follow; and

d) a transmission system state was classified as congested whenever the assessment indicated generator re-dispatch would need to occur in preparation for contingencies, with further explanation to follow.

Operators normally maintain the transmission system in a state of preparedness for any possible outage of a single system element (also called a Category B contingency). When the transmission system is in a state of preparedness, no Category B contingency can cause any transmission line to experience thermal criteria violations. Operators may need to prepare for contingencies by re-configuring the transmission system and/or dispatching generators out of merit to relieve constraints[8].

The Planning Report shows constraints in the Study Area are expected to be caused by the need to transfer excess power to other parts of the transmission system[9]. The Planning Report identified the outage of the Eastern Alberta Transmission Line (EATL) as an important reason why constraints might occur in the Study Area[10]. EATL is dispatchable. Re-dispatching EATL can mitigate constraints that occur because of other contingencies in many situations. However, the EATL contingency itself needs to be mitigated in a different way. Therefore, the congestion assessment analyzed only the EATL contingency, and generator curtailment was the applicable means of mitigating constraints. The dispatch of EATL does not affect post-contingency congestion results because the only such results have EATL out of service.

The AESO's operating practice usually requires that generators are re-dispatched for constraint relief in a Category A state whenever such mitigation is needed to ensure that no Category B contingency can cause thermal criteria violations. However, Remedial Action Schemes (RAS) that limit the required amount of pre-contingency curtailment can be developed and applied. RASs can detect contingency events by monitoring the status of system elements, and quickly and automatically curtail the output of generators in response to those events.

This congestion assessment hypothesized the existence of a generation shedding RAS to ensure the amount of pre-contingency curtailment was not over-estimated. The hypothetical RAS was assumed to respond to relevant Category B events[11] by shedding generation in proportion to the magnitude of overload on monitored transmission lines. Shedding generation may have limited effectiveness at reducing the loading of transmission lines. For example, shedding 10 MW of generation might only reduce the loading of one specific transmission line by 3 MW, because other lines also transfer power away from the generator whose output is reduced. For each transmission line where loading was mitigated by RAS, the AESO estimated constants of proportionality relating transmission line loading reduction to generation shedding that applied in various conditions. Such constants are called "effectiveness factors".

Sudden generation shedding can have adverse consequences. The immediate short-term consequence of generation shedding is that approximately the same amount of power that was shed flows into Alberta on the interties. The permissible instantaneous increase in imports is limited because of the risks of voltage collapse, voltage fluctuation, and overloads on or near the interties. Consequently, the

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[8] A constraint is an equipment limit or operating limit that would be exceeded if no mitigation measures were implemented. A constraint is different from a violation of reliability criteria because constraints can be in effect when the system is not violating any reliability criteria. For example, a constraint would be in effect if the in-merit generator dispatch would cause a thermal criteria violation to occur. The constraint would be in effect whether the violation had been prevented from occurring by constraining generators, or not. In the former case, the constraint would have been "relieved", or "mitigated", and in the latter case it would not have been.

[9] See Section 4.4 in the Planning Report.

[10] See Table 4.1 in the Planning Report.

[11] Specifically, in this assessment, outage of EATL

hypothetical RAS considered in this congestion analysis was limited to shedding an amount of generation no higher than the current Most Severe Single Contingency (MSSC), which is 466 MW[12].

For the purposes of the congestion assessment, whenever a thermal criteria violation was observed in a system state under assessment, the applicable aggregate effectiveness factor was used to assess the amount of generation shedding required to mitigate the thermal criteria violation. If the required amount of generation shedding was larger than the MSSC, then pre-contingency curtailment was deemed to be required, and the state was counted as congested. States in which no thermal criteria violations occurred were counted as un-congested. Likewise, states with thermal criteria violations that could be fully mitigated by post-contingency RAS response were counted as un-congested.

Line ratings were not used directly when "Category A-MSSC" congestion was assessed; instead, loading thresholds based on line ratings and effectiveness factors were used. The loading threshold of a transmission line was derived from the normal seasonal line rating, but a margin was added representing the amount of loading that could be relieved by shedding 466 MW of generation in the Study Area. The applicable loading thresholds are documented in Section 3.1.4.

Figure 2 - Loading Threshold

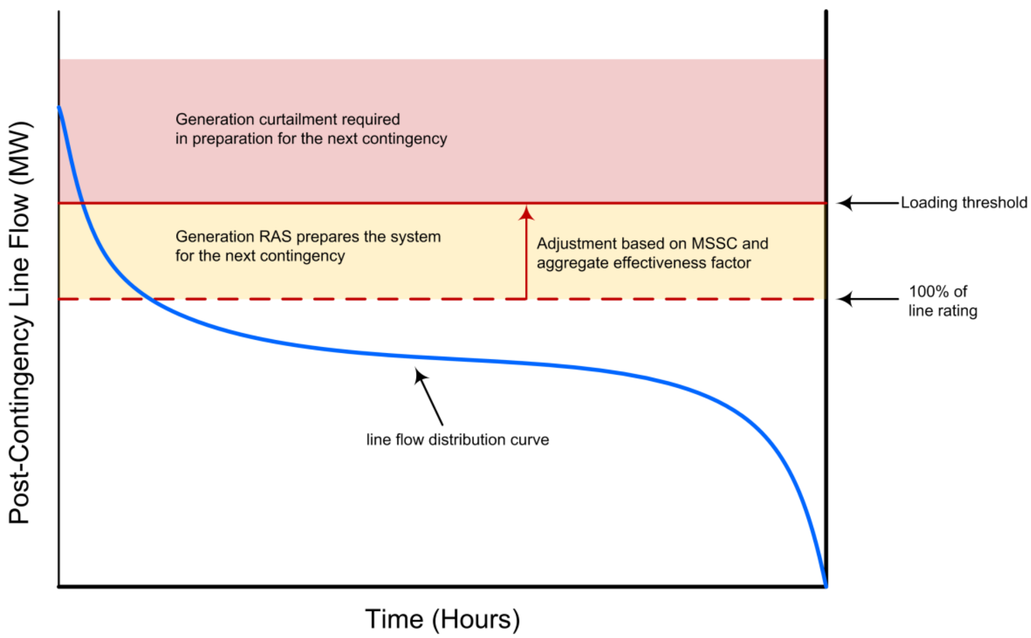

Figure 2 shows how loading thresholds relate to congestion assessment. The blue curve represents a time series of hourly transmission line flow values sorted by magnitude. Each point on the curve represents the loading the transmission line would have had if a contingency had occurred in a given hour. For a certain percentage of time, starting when the blue curve intersects the dashed red line, the

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[12] Formally, the MSSC can be loss of 1201L. In this report "MSSC" refers to the largest possible Category B loss of generation event, which is Genesee Unit #3.

post-contingency loading of the transmission line would exceed its rating if the contingency occurred. When the blue line is in the orange zone, the contingency can entirely be mitigated using RAS. When the duration curve is inside the red zone, RAS-based generation curtailment would be inadequate and pre-contingency generation curtailment would be required. The MSSC-based loading threshold occurs at the loading amount where the duration curve enters the red zone. The percentage of time the blue curve is in the red zone is the percentage of time that “Category A-MSSC” congestion occurs.

2.1.3 Consolidated Category A Congestion

Consolidated Category A congestion occurs whenever Category A and/or Category A-MSSC congestion is occurring. The results are consolidated such that hours are not double-counted.

2.2 Congestion Assessment under Category B

When Category B congestion was assessed:

a) one system element was out of service at all times;

b) generation dispatch was determined as if the system had no transmission constraints;

c) contingency events beyond the single element outage noted in (a), or preparations for such events, were not contemplated; and

d) a transmission system state was classified as congested whenever any monitored transmission line in the Study Area had loading above its seasonal normal rating.

For the reasons discussed in Section 2.1.2, the only outage considered in the congestion assessment was EATL. If additional outages were included, then more congested hours might have been identified.

The Category B assessment was performed to indicate how often congestion would occur if the transmission system were to have no RAS.

3 Modeling and Assumptions

The key inputs for congestion assessment include the load forecast, future generation capacity assumptions, generator dispatch assumptions, and transmission system assumptions. These inputs are discussed in the sections below.

3.1.1 Load Assumptions

The *AESO 2019 Long-term Outlook* (2019 LTO)[13] Reference Case load forecast was used for the congestion assessment. The hourly point-of-delivery (POD) load forecast was used to capture localized hourly load patterns.

Variation in load affects transmission line power flows. For this congestion assessment, based on the relationship between temperature and load, five weather-synchronized hourly load profiles were created

[13] The 2019 LTO is available on the AESO website.

and analyzed to account for the effects of weather. Additionally, five hourly wind profiles corresponding to the weather assumptions were created.

3.1.2 Generation Capacity Assumptions

Existing Generation

The Study Area had 2,321 MW of existing generation as of January 2020 including Battle River 4, and 5 (BR4, BR5) and Sheerness 1 and 2 (SH1, SH2).

Future Renewable Generation

The Study Area has renewable wind and solar energy resources that are considered suitable for development of renewable generation projects. However, the locations, sizes, and energization dates of future generating facilities are uncertain.

The 2019 LTO Alternate Renewable Policy Case[14] was chosen as a starting point for congestion assessment to evaluate a relationship between new renewable generation in the Study Area and the likelihood of congestion risks in the Study Area. The 2019 LTO Alternate Renewable Policy Case represents an outlook for the Alberta generation fleet wherein development is driven by a renewable energy target or a public policy that supports greater renewable development compared to the 2019 LTO Reference Case.

The assumed timing for renewable generator additions was based on the 2019 LTO Alternate Renewable Policy Case. The assumed locations and sizes of individual generating facilities were informed by the generation integration capability planning studies results outlined in the Planning Report. Among the forecasted renewable generator additions were the REP projects and some generic renewable projects. The REP projects were represented using their planned sizes, locations, and in-service dates. The locations of generic renewable projects were chosen to use existing transmission infrastructure as efficiently as possible. The study period was 2023 to 2029 in which renewable generator additions were forecasted to occur in the 2019 LTO Alternate Renewable Policy Case.

The locations and sizes of new wind and solar generators modeled in the congestion assessment that are within the Study Area are listed in Table 1.

Table 1 –Forecast Renewable Generation Capacity Additions in Study Area

Asset Name	Capacity (MW)	Connected via Substation	Technology	In-service Year
Sharp Hills Wind Farm (REP)	248	New Brigden 2088S	Wind	Pre-2023
Buffalo Atlee Wind Farm 1 (REP)	17	Jenner 275S	Wind	Pre-2023
Buffalo Atlee Wind Farm 2 (REP)	14	Jenner 275S	Wind	Pre-2023

[14] A description of the Alternate Renewable Policy is included in the 2019 LTO on the AESO website.

Asset Name	Capacity (MW)	Connected via Substation	Technology	In-service Year
Buffalo Atlee Wind Farm 3 (REP)	17	Jenner 275S	Wind	Pre-2023
Cypress Wind Power Project (REP)	202	Woolchester 1019S	Wind	Pre-2023
Jenner Wind Power Project (REP)	122	Jenner 275S	Wind	Pre-2023
Jenner Wind Power Project 2 (REP)	71	Halsbury 306S	Wind	Pre-2023
SE New Wind 1	200	Whitla 251S	Wind	2023
CE New Wind 1	200	Lanfine 959S	Wind	2023
SE New Wind 2	200	Bowmanton 244S	Wind	2024
CE New Wind 2	150	Nilrem 574S	Wind	2024
CE New Wind 3	150	Edgerton 899S	Wind	2025
CE New Wind 4	150	Lanfine 959S	Wind	2026
CE New Wind 5	150	Pemukan 932S	Wind	2027
CE New Wind 6	150	Drury 2007S	Wind	2028
CE New Wind 7	150	Pemukan 932S	Wind	2029
CE Solar 1	50	Pemukan 932S	Solar	Pre-2023
CE Solar 2	50	Pemukan 932S	Solar	Pre-2023
CE Solar 3	30	Pemukan 932S	Solar	2023
SE Solar 1	22	Suffield 895S	Solar	Pre-2023

Future Thermal Generation

The Study Area contains thermal generating facilities that are anticipated to retire and be replaced. There is uncertainty regarding the timing, volume, and offer behavior of the replacement or retirement of the existing thermal generation in the CE sub-region. Therefore, two different scenarios were created and assessed to help the AESO understand how thermal generation capacity and dispatch could affect the probability of congestion in the Study Area.

Baseload Scenario

The Baseload Scenario assumed that new gas-fired generators would replace coal-fired units Battle River 3 and 4 (BR3 and BR4) by 2023, and the replacements would have the same capacity as the coal units. Similarly, the other coal units in the Study Area (at Battle River and Sheerness) were assumed to be replaced by gas units, but at later dates.

The Baseload Scenario assumed all thermal units referred to in Table 2 would have similar production profiles to baseload units. Baseload units are expected to have reliable energy output, produce at least minimum stable generation during low-price periods, and produce relatively stable output at other times. Baseload units are relatively efficient and price-competitive.

Peaking Scenario

The Peaking Scenario assumed that BR4 would be retired by 2025, and BR3 and BR4 would not be replaced, so the Study Area had thermal generating capacity reduced from historical levels.

The Peaking Scenario assumed all thermal units referred to in Table 2 would have similar production profiles to peaking units. Peaking units are expected to cycle up and down depending on market price, and might not be running during low price hours, including hours when renewable energy production is relatively high.

Table 2 provides further details about the scenarios.

Table 2 – Relevant Thermal Generators in the Study Area

Facility	Capacity	2023	2024	2025	2026	2027	2028	2029
BR3	149	New gas-fired generation Baseload unit						
BR4	155	New gas-fired generation Baseload unit						
BR5	385	Baseload unit						
SH1	400	Baseload unit						
SH2	390	Baseload unit						
Total (MW)	1,479	1,479						

(a) Baseload Scenario

Facility	Capacity	2023	2024	2025	2026	2027	2028	2029
BR3	149	Retired						
BR4	155	Peaking unit			Retired			
BR5	385	Peaking unit						
SH1	400	Peaking unit						
SH2	390	Peaking unit						
Total (MW)	1,479	1,330			1,175			

(b) Peaking Scenario

Generation Capacity Summary

The existing generation baseline and incremental generation (based on Table 1 and Table 2) studied in the congestion assessment are summarized in Table 3.

Table 3 – Summary of Generation Capacity (MW) in the Study Area

	2023	2024	2025	2026	2027	2028	2029
Existing Capacity	2,321						
Retirement	-155	-155	-155	-155	-155	-155	-155
New Gas Replacement	304	304	304	304	304	304	304
Future REP Projects	692	692	692	692	692	692	692
New CE Wind	200	350	500	650	800	950	1100
New SE wind	200	400	400	400	400	400	400
New CE Solar	130	130	130	130	130	130	130
New SE Solar	22	22	22	22	22	22	22
Total New Renewable*	1,250	1,600	1,750	1,900	2,050	2,200	2,350
Total Incremental Generation*	1,400	1,750	1,900	2,050	2,200	2,350	2,500

(a) Baseload Scenario

	2023	2024	2025	2026	2027	2028	2029
Existing Capacity	2,321						
Retirement				-155	-155	-155	-155
New Gas Replacement	0	0	0	0	0	0	0
Future REP Projects	692	692	692	692	692	692	692
New CE Wind	200	350	500	650	800	950	1100
New SE wind	200	400	400	400	400	400	400
New CE Solar	130	130	130	130	130	130	130
New SE Solar	22	22	22	22	22	22	22
Total New Renewable*	1,250	1,600	1,750	1,900	2,050	2,200	2,350
Total Incremental Generation*	1,250	1,600	1,750	1,750	1,900	2,050	2,200

(b) Peaking Scenario

* rounded to the nearest 50 MW

3.1.3 Generation Dispatch Assumptions

Generation dispatch assumptions are aligned with the 2019 LTO Alternate Renewable Policy Scenario. This section provides a high-level overview of generation dispatch assumptions for the various technologies that were modeled.

Thermal Generation

Current thermal assets are modeled using historical information to guide the inputs. Future thermal assets are modeled using generic technology models based on similar existing technology.

In arriving at the bidding assumptions, the AESO analyzed historical data, researched industry information and set up an Aurora model to reflect the supply and demand fundamentals of the future Alberta power market. The offer prices for all assets in Aurora were based on technology costs and bidding behaviors. Technology costs include fuel cost, startup cost, emission cost and variable operating and maintenance (VOM) cost. To capture the market behaviour of units within the wholesale electricity market, adjustments were made to technology costs based on historical observations of bidding behaviors.

Minimum stable generation levels of thermal units were modelled to capture operating characteristics of those units. As such, whenever a unit was operating, its output was greater than or equal to the minimum stable generation level.

Forced outage rates assumptions were based on a seasonal distribution of time-to-fail and time-to-repair hours for coal, combined cycle, simple cycle units greater than 20 MW and biomass generating units. Forced outage rates were estimated using historical available capability data to ensure that the historical behaviour was captured in Aurora. The AESO analyzed historical planned outages based on available capability data and estimated an outage pattern for each generating asset such that the daily reserve margin in the transmission system is maximized.

Production from thermal units, such as combined cycle, simple cycle, coal and coal to gas units, were modeled based on dispatch prices and demand levels. When meeting the hourly demand level, units with the lowest dispatch prices were selected first. In line with the 2019 LTO Alternate Renewable Policy scenario, carbon prices within the model average $30/tonne.

Wind and Solar

For each geographical region, hourly wind and solar profiles were used in the model to capture seasonal and hourly variability. As the majority of new generation assumed in the Study Area was wind generation, five representative weather years were chosen to capture a good range of variation in wind production. For each weather year, one production profile was created for existing wind generating units and one profile was created for future wind generators, in order to account for technological advancements and location diversification.

Hydro

The AESO used historical values to model hydro units to capture the daily and seasonal patterns of the actual observed hydroelectric generation dispatches.

3.1.4 Transmission System Assumptions

Network Topology

The Alberta Interconnected Electric System (AIES) was modeled in its entirety. The transmission system's three interties, to British Columbia, Saskatchewan, and Montana, were modeled. The neighboring jurisdictions had simplified representations. Intertie transfer capability was established based on historical performance. Flows on interties were predicted based on price differentials yielded by production cost modeling.

Future transmission system developments modeled in the congestion assessment are the same as those modeled in the planning studies of the Planning Report, with the following exceptions.

For the congestion assessment:

a) the Chapel Rock to Pincher Creek Transmission Development (CRPC) was not included for the pre-CETO and post-CETO first circuit network topologies, but CRPC was included for the post-CETO second circuit topology; and
b) stages 1 and 2 of the Provost to Edgerton and Nilrem to Vermilion Transmission Development (PENV) were assumed to be in service and operated at 240 kV throughout.

However, for the planning studies:

a) sensitivity studies were carried out with and without CRPC in place; and
b) PENV was assumed to be energized at 138 kV initially, and re-energized at 240 kV later.

Monitored Branches and Ratings

The following transmission lines were monitored in the congestion assessment:

- 912L (Nevis 766S – Red Deer 63S)
- 9L20 (Cordel 755S – Nevis 766S)
- 174L (North Holden 395S – Bardo 197S)
- 701L (Strome 223S – North Holden 395S)

These transmission lines were monitored because the EATL contingency caused them to be overloaded in the planning studies, and they are needed for transferring power out of the Study Area.

Normal ratings for monitored transmission lines are listed in Table 4. As discussed in Sections 2.1.1 and 2.1.3, they were used for Category A and Category B congestion assessment.

Table 4 - Normal Ratings for Monitored Transmission Lines

Transmission Line	Voltage Rating (kV)	Thermal Rating (MVA)	
		Summer	Winter
912L	240	507	623
9L20	240	488	498
174L	138	96	96
701L	138	119	146

Category A – MSSC Loading Thresholds

Table 5 lists the loading threshold values that were used in Category A-MSSC congestion assessment, as discussed in Section 2.1.2.

Table 5 – Category A – MSSC Loading Thresholds

Transmission Line	Voltage Rating (kV)	MSSC Category A Threshold (MVA)					
		Pre-Development		Post-CETO One Circuit		Post-CETO Second Circuit	
		Summer	Winter	Summer	Winter	Summer	Winter
912L	240	592	760	636	760	631	760
9L20	240	583	585	615	625	610	621
174L	138	112	112	123	123		
701L	138	129	164	131	164		

Line Rating Adjustment for Reactive Power

Aurora uses a linearized DC model for power flow calculations. The thermal ratings of transmission lines were adjusted from MVA to MW using an approximate power factor of 0.95. The MW ratings are reduced to account for capacity that might be used for reactive power.

HVDC Dispatch

The HVDC lines, being the Western Alberta Transmission Line (WATL) and EATL, were dispatched to minimize system losses in the congestion assessment. A formula that estimates the minimum loss dispatch based on flows measured on certain alternating current (AC) transmission lines was used to determine the HVDC dispatch that should be used for each hour in each simulation.

Aggregate Effectiveness Factors

The effectiveness factors used in the Category A-MSSC congestion assessment are given in Table 6. Each effectiveness factor is the amount (in MW) of loading relief achieved per unit of generator curtailment (in MW) that is applicable to a specific transmission line after a specific contingency has occurred. For example, to reduce loading on 174L by 1 MW when the EATL contingency is in effect, the amount of generator curtailment required is 1 MW / 0.034 = 29 MW.

The effectiveness factors reflect the aggregate effectiveness of a collection of generators that might be curtailed. They depend on the anticipated dispatches of the set of generators available to be curtailed, and consequently vary from season to season despite constant topology.

Table 6 – Effectiveness Factors

Transmission Line	Contingency	Pre-Development	
		Summer	Winter
174L	EATL	0.034	0.034
701L	EATL	0.021	0.039
912L	EATL	0.18	0.29
9L20	EATL	0.20	0.19

4 Congestion Assessment Results

Congestion assessment was performed for various renewable generation development levels from 1,250 MW to 2,350 MW. Five iterations of market simulation were performed for each new renewable capacity development level, using the weather-synchronized load and wind profiles introduced in Section 3.1.1. The bands for congestion shown in the figures in this section were plotted by using these profiles to establish lower and upper bounds. The percentages of congested hours in each year were calculated using the methods outlined in Section 2.1.

4.1 Congestion Duration, Pre-CETO Transmission Development

Figure 3 shows the percentage of time congestion is observed in the Baseload and Peaking Scenarios as a function of new renewable generating capacity in the Study Area. Congestion increases as renewable generation is added, in both scenarios. As expected, the Baseload Scenario has a higher probability of congestion than the Peaking Scenario. Table 7 shows the average percentage of congested hours as a function of incremental generation. The results from the five load profiles comprise the average.

Figure 3 – Percentage of Time with Congestion, Pre-CETO

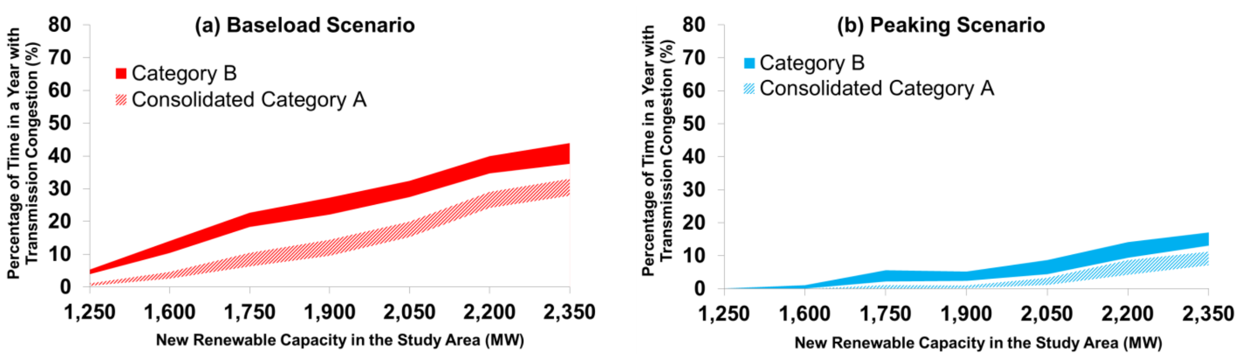


Table 7 – Average Percentage of Time with Congestion, Pre-CETO

	New Renewable Capacity in the Study Area (MW)						
	1,250	1,600	1,750	1,900	2,050	2,200	2,350
Category B	4.6	12.5	20.8	24.8	30.0	37.7	41.2
Consolidated Category A	0.8	3.8	8.7	12.4	17.6	26.0	30.2
• Category A-MSSC	0.7	3.1	7.6	10.9	15.8	24.7	28.8
• Category A	0.5	2.2	4.8	6.1	10.0	17.6	22.6

(a) Baseload Scenario

	New Renewable Capacity in the Study Area (MW)						
	1,250	1,600	1,750	1,900	2,050	2,200	2,350
Category B	0.1	0.6	3.8	3.8	6.4	11.9	15.5
Consolidated Category A	-	0.0	0.6	0.7	2.2	6.2	9.2
• Category A-MSSC	-	0.0	0.6	0.7	2.2	6.2	9.2
• Category A	-	-	-	0.0	0.1	1.5	4.0

(b) Peaking Scenario

Transmission Line Loading Sensitivity

The preceding congestion statistics were calculated assuming that curtailment would begin when pre- or post-contingency transmission line loading (as applicable) would reach 100% of the rating or threshold (as applicable). However, operators may need to curtail generation before transmission line loadings reach or exceed ratings in real-time operation. To quantify this risk, congestion statistics were re-evaluated under the assumption that curtailment would begin when pre- or post-contingency loading reached 95% of the applicable limit. The results are given in Figure 4 and Table 8. As shown, congestion statistics are sensitive to this assumption. A small change in curtailment threshold can lead to a significant change in the percentage of hours in which congestion is observed.

Figure 4 - Percentage of Time with Congestion, Pre-CETO, 95% of Rating or Threshold

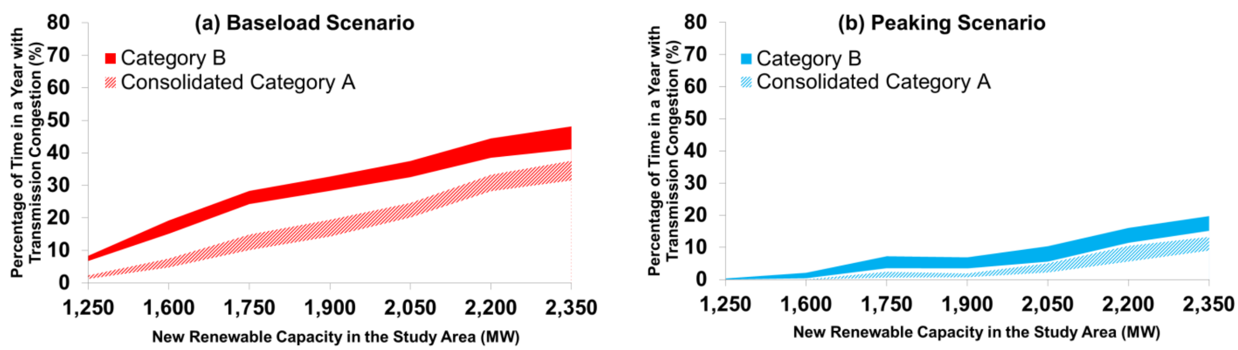


Table 8 - Average Percentage of Time with Congestion, Pre-CETO, 95% of Rating or Threshold

	New Renewable Capacity in the Study Area (MW)						
	1,250	1,600	1,750	1,900	2,050	2,200	2,350
Category B	7.6	17.3	26.1	30.6	35.1	42.1	45.4
Consolidated Category A	1.9	6.6	12.8	16.9	22.3	30.5	34.5
• Category A-MSSC	1.4	5.3	11.2	15.1	20.4	29.0	32.7
• Category A	1.3	4.3	7.4	9.1	13.9	21.8	26.5

(a) Baseload Scenario

	New Renewable Capacity in the Study Area (MW)						
	1,250	1,600	1,750	1,900	2,050	2,200	2,350
Category B	0.2	1.2	5.2	5.1	8.0	14.1	17.8
Consolidated Category A	0.0	0.1	1.4	1.4	3.5	7.9	11.2
• Category A-MSSC	0.0	0.1	1.4	1.4	3.5	7.9	11.2
• Category A	-	-	0.0	0.0	0.3	2.7	5.9

(b) Peaking Scenario

4.2 Congestion Duration, Post CETO, First Circuit

Figure 5 and Table 9 show the percentage of congested hours, supposing the first circuit of CETO has been energized. Energizing the first circuit reduces congestion.

Figure 5 – Percentage of Time with Congestion, Post CETO First Circuit

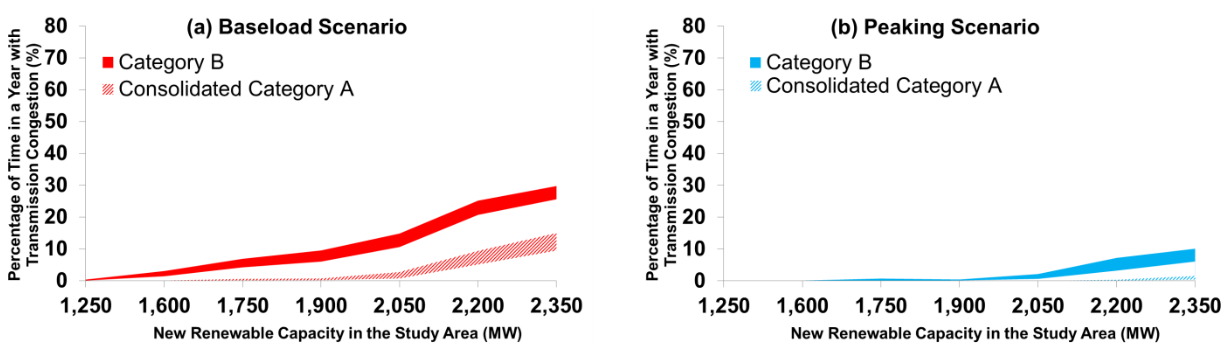


Table 9 – Average Percentage of Time with Congestion, Post CETO First Circuit

	New Renewable Capacity in the Study Area (MW)						
	1,250	1,600	1,750	1,900	2,050	2,200	2,350
Category B	0.2	2.1	5.9	8.0	13.1	22.9	27.3
Consolidated Category A	-	0.0	0.3	0.5	1.8	7.8	12.3
• Category A-MSSC	-	0.0	0.2	0.3	1.0	5.3	8.9
• Category A	-	0.0	0.1	0.3	1.4	6.6	11.1

(a) Baseload Scenario

	New Renewable Capacity in the Study Area (MW)						
	1,250	1,600	1,750	1,900	2,050	2,200	2,350
Category B	-	0.0	0.3	0.3	1.2	5.1	7.9
Consolidated Category A	-	-	-	-	0.0	0.2	1.0
• Category A-MSSC	-	-	-	-	0.0	0.2	0.9
• Category A	-	-	-	-	-	0.0	0.5

(b) Peaking Scenario

4.3 Congestion Duration, Post CETO, Second Circuit

The second circuit of CETO facilitates a further reduction in the percentage of congested hours, compared to the first circuit only, as new renewable generating capacity in the Study Area increases. A RAS was identified as helpful for enabling the full value of the second circuit of CETO to be realized. The RAS would monitor the loading of 138 kV transmission lines 174L, 7L53, and 7L92, and open these lines as needed (to prevent thermal criteria violations) in response to the EATL contingency. The second circuit of CETO, in conjunction with the RAS, increases the amount of generating capacity that can be accommodated in the Central East sub-region. Figure 6 and Table 10 show the percentage of congested hours, supposing the second circuit of CETO has been energized.

Figure 6 - Percentage of Time with Congestion, Post CETO Second Circuit

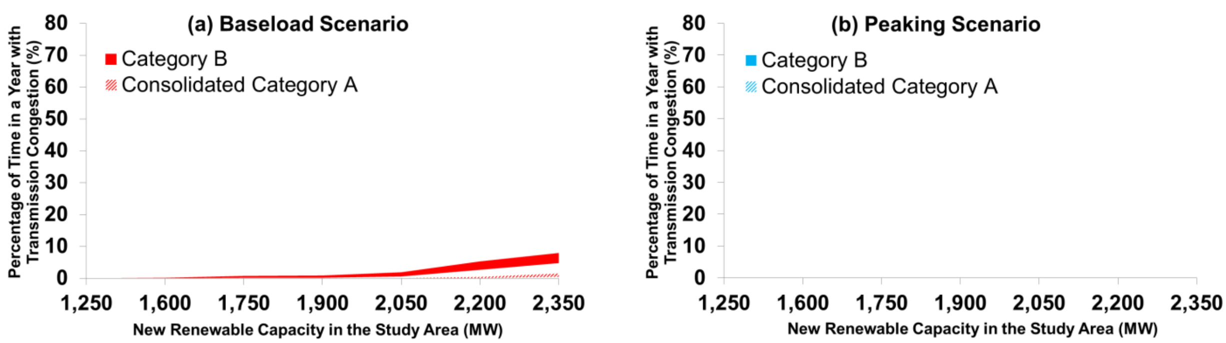


Table 10 - Average Percentage of Time with Congestion, Post CETO Second Circuit

	New Renewable Capacity in the Study Area (MW)						
	1,250	1,600	1,750	1,900	2,050	2,200	2,350
Category B	-	0.1	0.3	0.5	1.4	3.9	6.5
Consolidated Category A	-	-	-	0.0	0.0	0.2	1.0
• Category A-MSSC	-	-	-	0.0	0.0	0.1	0.2
• Category A	-	-	-	0.0	0.0	0.2	0.9

(a) Baseload Scenario

	New Renewable Capacity in the Study Area (MW)						
	1,250	1,600	1,750	1,900	2,050	2,200	2,350
Category B	-	-	-	-	-	-	0.0
Consolidated Category A	-	-	-	-	-	-	-
• Category A-MSSC	-	-	-	-	-	-	-
• Category A	-	-	-	-	-	-	-

(b) Peaking Scenario

4.4 Congestion Magnitude

In previous sections, transmission system congestion was quantified using percentage of time. To show the magnitude of congestion, line loading distribution curves (sorted hourly line flows) for each monitored transmission line are provided in Attachment A.

Figure 7 and Figure 8 are figures from Attachment A that show pre-CETO line loading distribution curves for 9L20[15], based on the Baseload Scenario. Each curve represents a loading distribution curve of the hourly 9L20 flows for the new renewable development level as shown in the legend. The points above the blue line in each curve represent states where the transmission line is congested. The magnitude of Category A and Category A-MSSC congestion is evaluated based on the overloading percentage and the applicable limits.

When congestion occurs on the transmission system, anticipated in-merit energy cannot be transmitted. To relieve the transmission system congestion, generation curtailment will be required. The amount of generation curtailment can be estimated using the applicable effectiveness factors. According to the assessment performed:

- To alleviate every 1 MW of congestion on the 138 kV transmission lines 174L and 701L, the average generation curtailment in the Study Area would be approximately 20 MW and 27 MW, respectively.
- To alleviate every 1 MW of congestion on the 240 kV transmission lines 912L and 9L20, the average generation curtailment in the Study Area would be approximately 4 MW.

[15] The line loading distribution curve for this line is shown as this transmission line is one of the most limiting one in terms of the Central East transfer out constraints.

Figure 7 – Line Loading Distribution Curves for 9L20, Category A Congestion, Pre-CETO

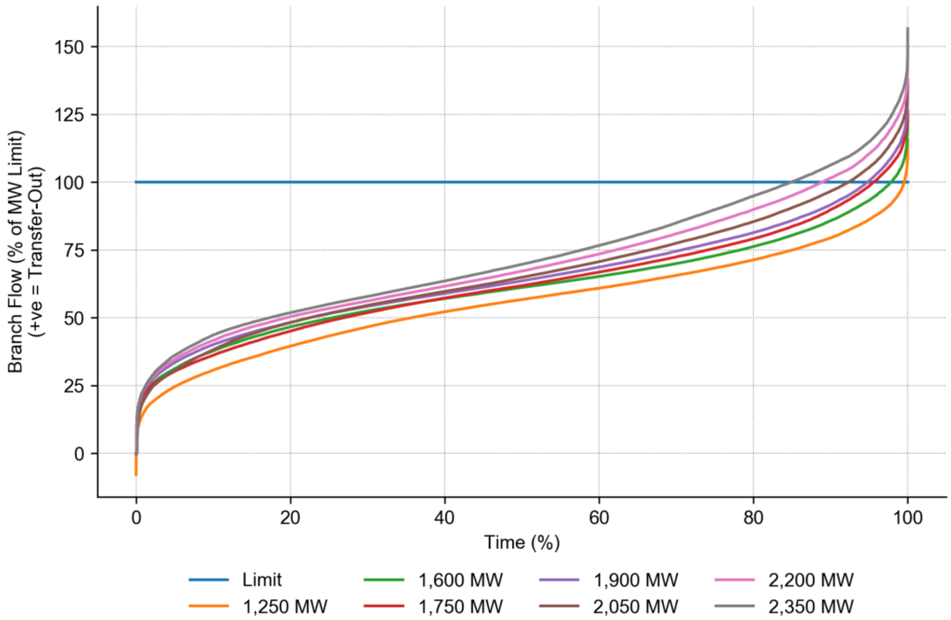


Figure 8 – Line Loading Distribution Curves for 9L20, Category A-MSSC Congestion, Pre-CETO

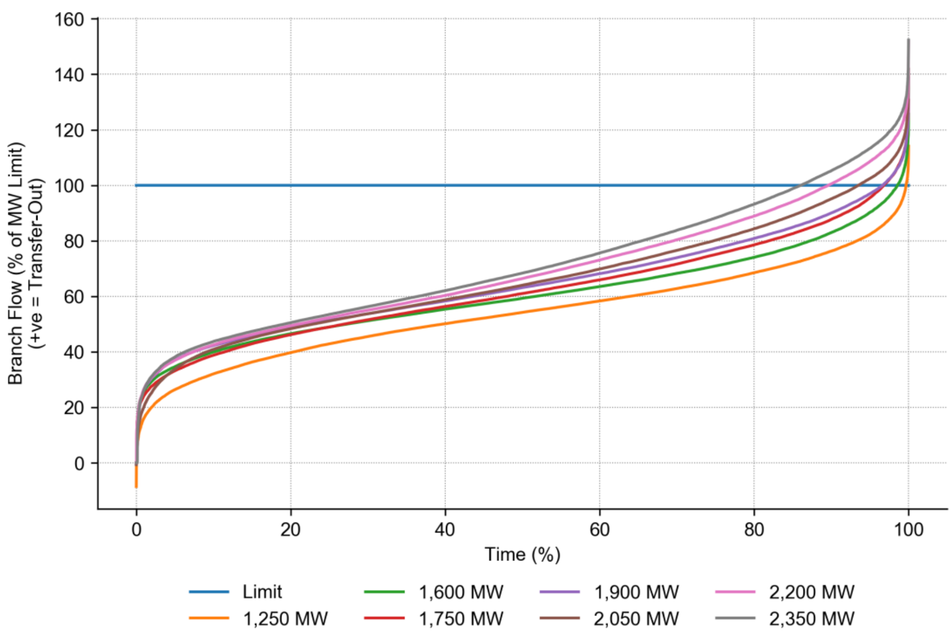


Figure 7 and Figure 8 can be used to quantify both the magnitude and the percentage of time of Category A and Category A-MSSC congestion related to 9L20. For example, suppose that 1,600 MW of new renewable generation has been added to the Study Area in the future. The green curve in Figure 7 is the curve for 9L20 loading that applies in this situation. The loading exceeds the line's normal rating approximately 2% of the time. Table 7 indicates Category A congestion in the Study Area will occur about 2.2% of the time overall. One concludes that 9L20 is very likely experiencing constraints when the Study Area experiences Category A congestion. Similarly, the 9L20 loading exceeds the line's loading threshold approximately 1.5% of the time. Table 7 indicates Category A-MSSC congestion in the Study Area will occur about 3.1% of the time overall.

The potential generation curtailment required to mitigate 9L20 constraints arising from the EATL contingency is not trivial and would grow significantly as new generation is added in the Study area. For example, suppose that 1,250 MW of new renewable generation has been added to the Study Area in the future (the orange curve in Figure 8). The loading exceeds the line's loading threshold approximately 0.3% of the time with the maximum magnitude of overload around 78 MW higher than the loading threshold. The estimated amount of energy that must be curtailed to mitigate constraints would be around 2,200 MWh, distributed among one or more effective generators, based on the applicable effectiveness factors. When the new renewable generation reaches 2,350 MW, the loading exceeds the line's loading threshold approximately 14% of the time with the maximum magnitude of overload around 290 MW higher than the loading threshold. The estimated amount of energy that must be curtailed to mitigate constraints would be around 310,280 MWh.

Several constraints can be in effect concurrently. When more than one constraint is in effect, sufficient curtailment to mitigate all of them must take place. For example, 912L and 9L20 constraints are related, and can occur at the same time. When 912L and 9L20 are concurrently overloaded, curtailment within the Study Area that is implemented to reduce loading on one of them also reduces loading on the other, with approximately equal effectiveness.

A collection of plots similar to Figure 7 and Figure 8, for other transmission lines, scenarios, and configurations of network topology, has been provided in Attachment A.

4.5 Summary

The risk of congestion as a result of incremental renewable generating capacity additions in the Study Area, both before and after the Preferred Transmission Development is implemented, has been quantified in Table 7 to Table 10. Overall, the Preferred Transmission Development is effective at reducing congestion.

The amount of congestion depends on generation in the Study Area. If new or refurbished thermal generators appear in the Study Area, their bidding behaviour affects the anticipated amount of congestion. If the thermal units behave like baseload units, then more hours of congestion can be expected to occur compared to peaking behaviour. As the percentage of congested hours increases, the average magnitude of thermal overload resulting in congestion can also be expected to increase. As generation capacity in the Study Area increases, the average magnitude of thermal overloads resulting in congestion will grow.

The expected percentage of hours that are congested increases steadily as incremental generation is added in the Study Area. There is clear positive correlation between line flows and the amount of new wind generation. Figure 9 shows an approximation of the joint probability distribution of outflow on 9L20 and wind generator output in the Study Area. A collection of plots similar to Figure 8 was provided in Attachment B.

Higher and lower probability of 9L20 loading is indicated by bright and dark areas, respectively. Flow measurements from the entire assessment (regardless of scenarios and renewable development levels) were used to build this empirical distribution. Figure 9 clearly shows the positive correlation between wind generation and 9L20 line flow. When wind generation is held at a fixed level of output, flow on 9L20 can vary, for reasons including the amount and distribution of system load and the dispatch of non-wind generators.

Figure 9: 9L20 Flow Density (Pre-CETO)

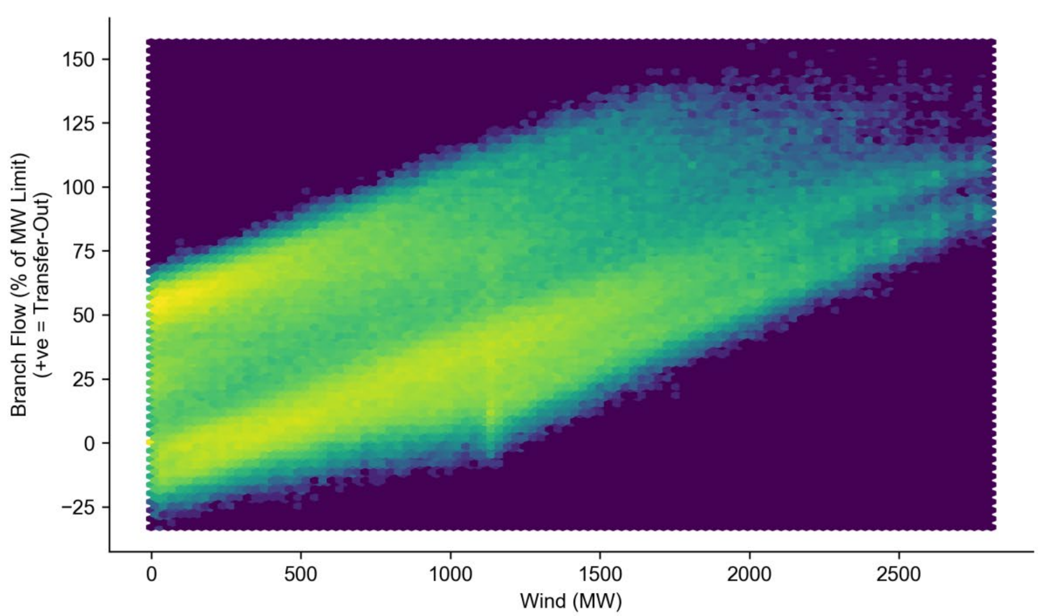


Table 11 below summarizes the Consolidated Category A congestion results before development and after the first and second circuits of the Preferred Transmission Development. These numbers were used to inform the establishment of construction milestones, which is discussed in the Planning Report.

Table 11: Summary of Consolidated Category A Congestion Results (Average % of Time with Congestion)

Status of CETO	Scenario	New Renewable Capacity in the Study Area (MW)						
		1,250	1,600	1,750	1,900	2,050	2,200	2,350
Pre-Project	Baseload	0.8	3.8	8.7	12.4	17.6	26.0	30.2
	Peaking	-	0.0	0.6	0.7	2.2	6.2	9.2
Post-CETO First Circuit	Baseload	-	0.0	0.3	0.5	1.8	7.8	12.3
	Peaking	-	-	-	-	0.0	0.2	1.0
Post-CETO Second Circuit	Baseload	-	-	-	0.0	0.0	0.2	1.0
	Peaking	-	-	-	-	-	-	-

Attachment A

Line Loading Distribution Curves

Figure A1 - Category A Congestion Peaking Scenario in Pre-CETO

Figure A1a - 912L Line Loading

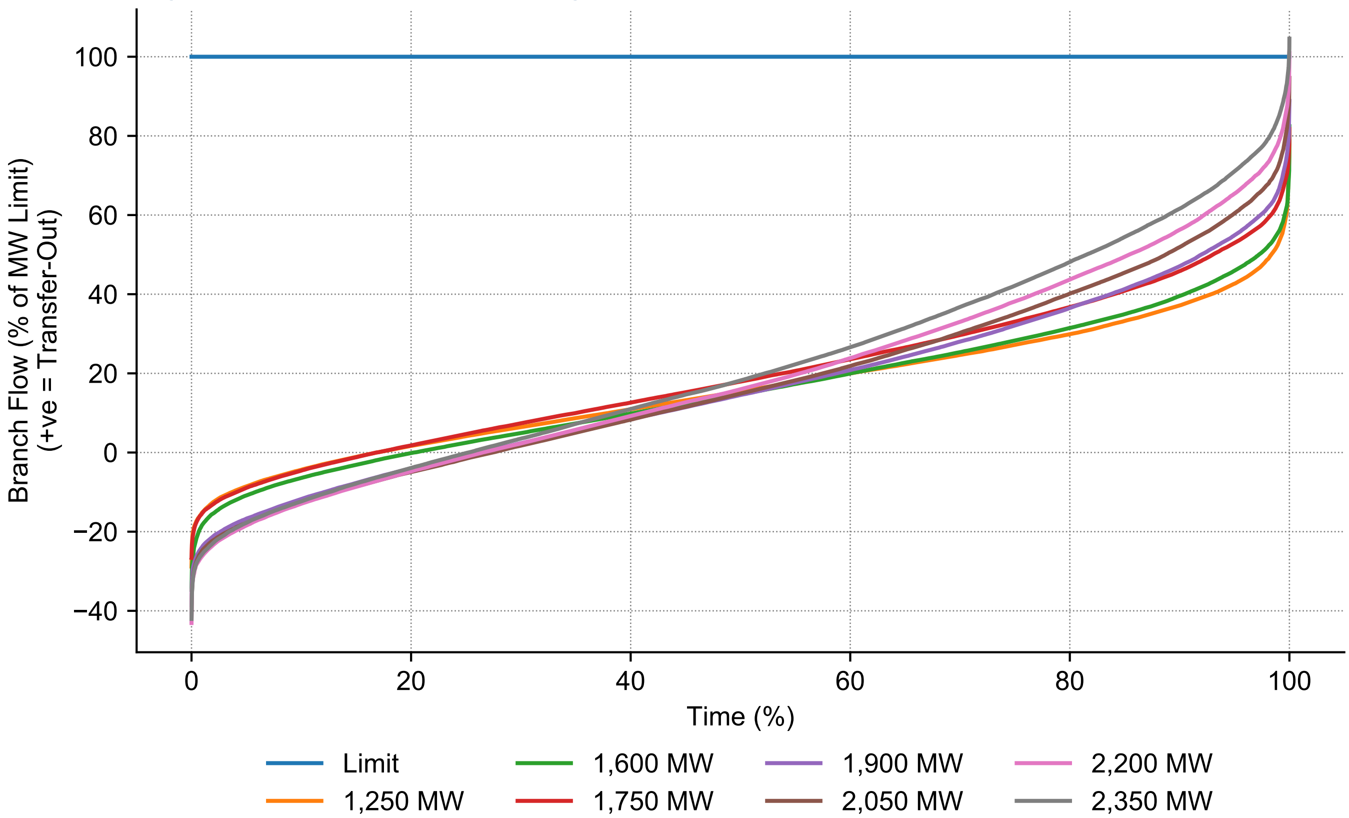


Figure A1b - 9L20 Line Loading

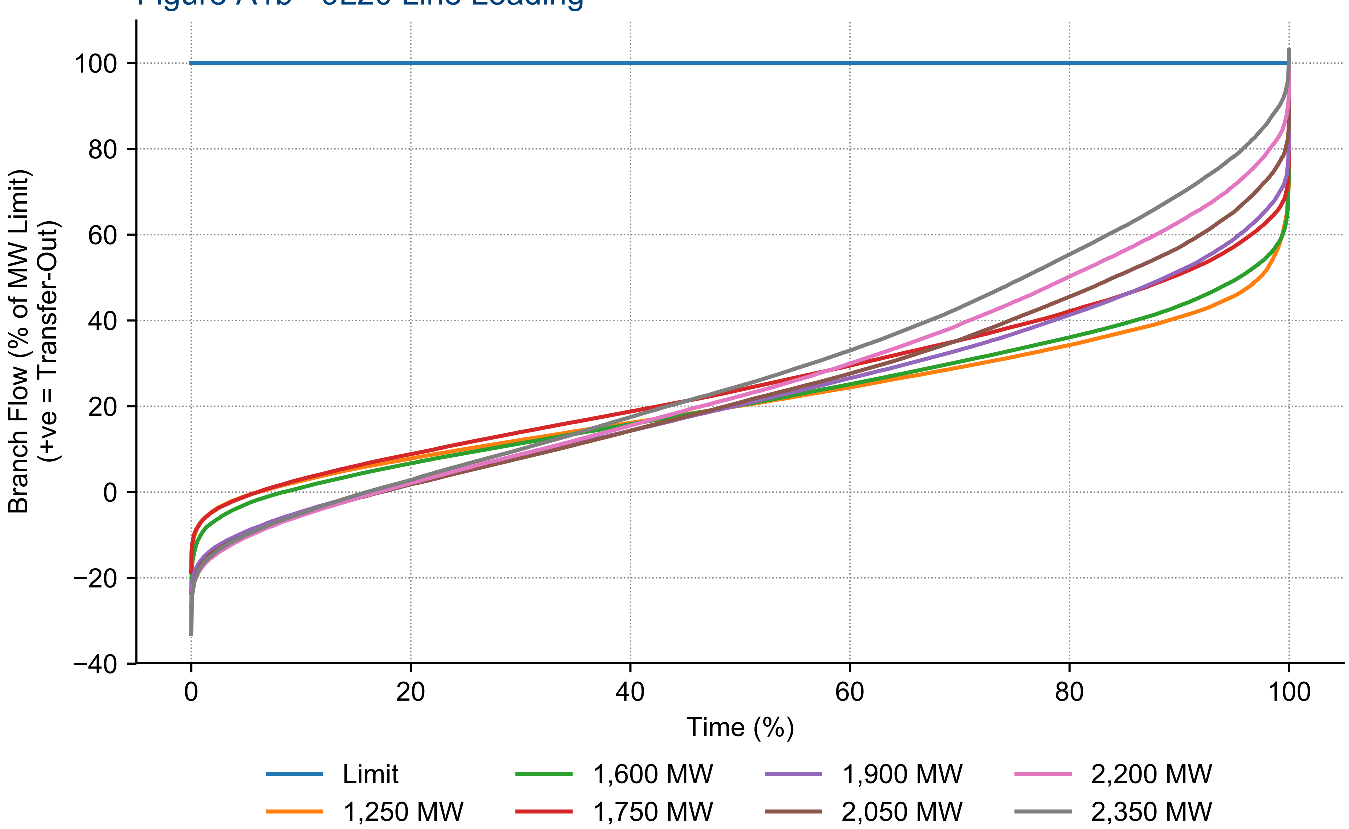


Figure A1c - 174L Line Loading

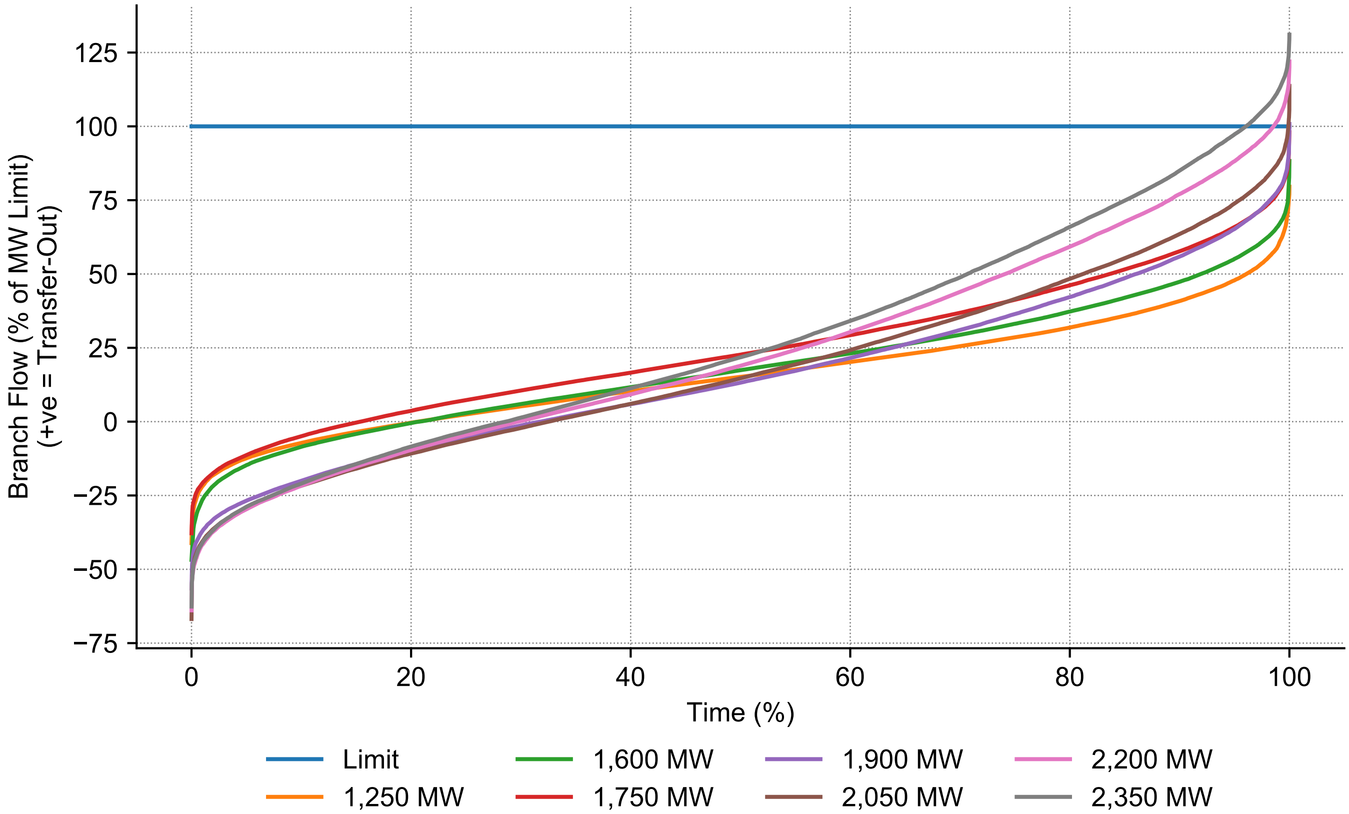


Figure A1d - 701L Line Loading

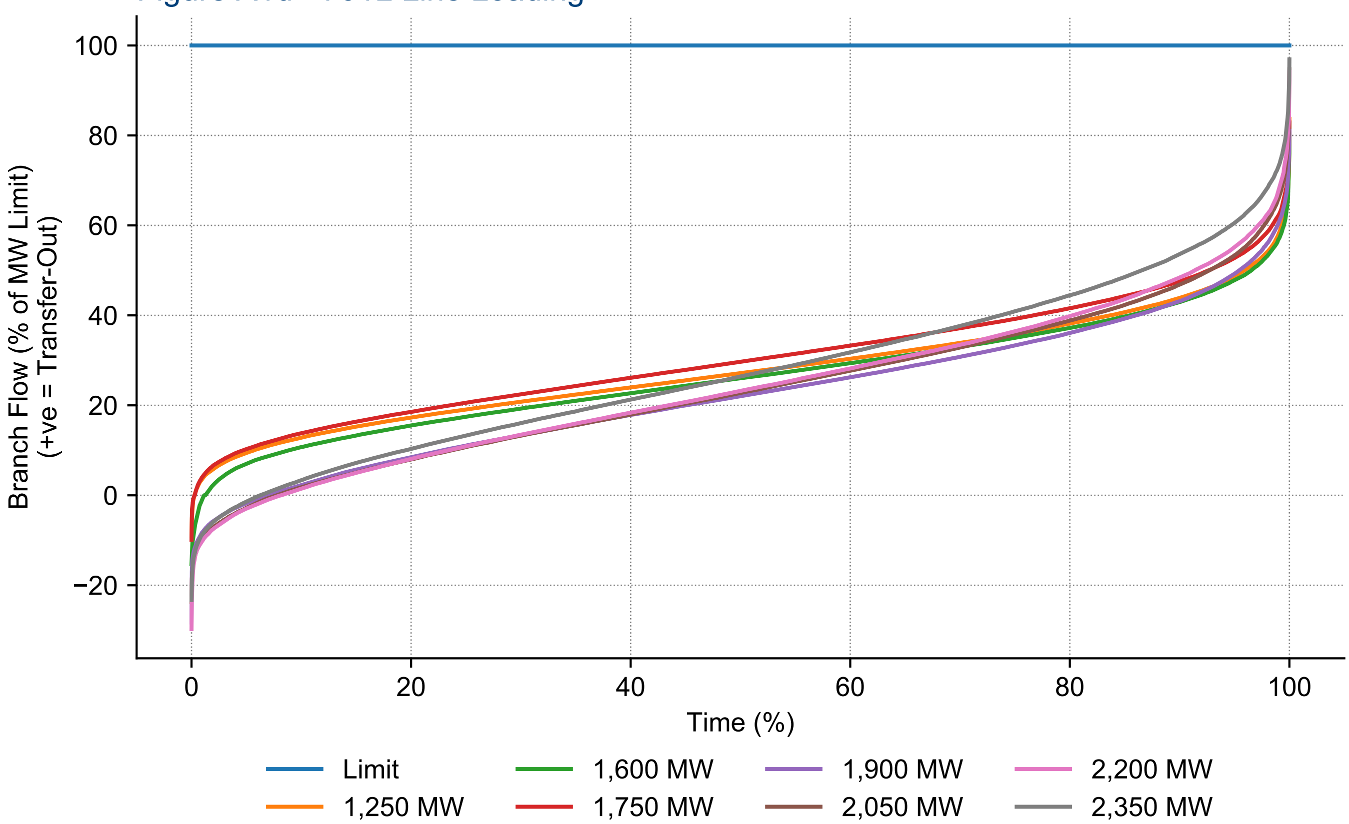


Figure A2 - Category A Congestion
Baseload Scenario in Pre-CETO

Figure A2a - 912L Line Loading

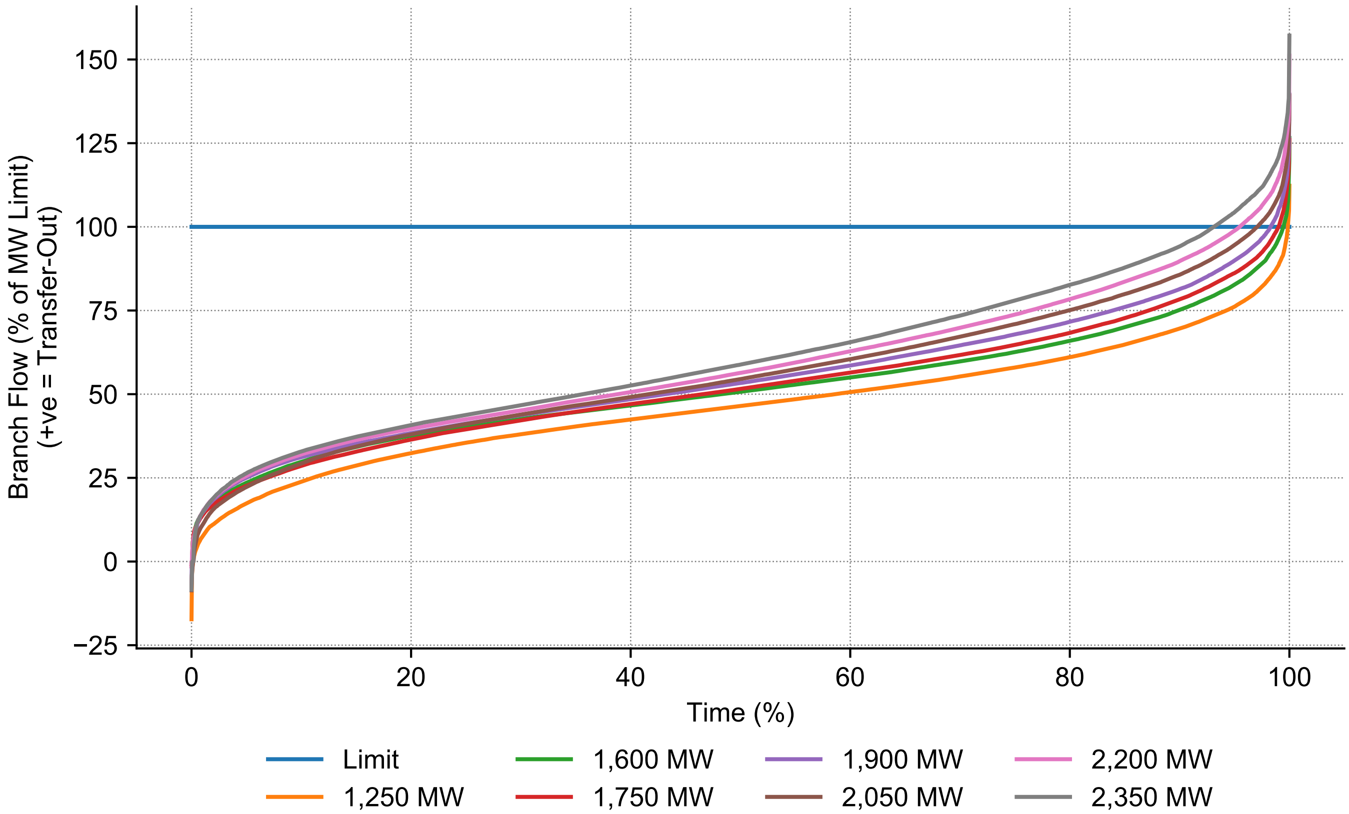


Figure A2b - 9L20 Line Loading

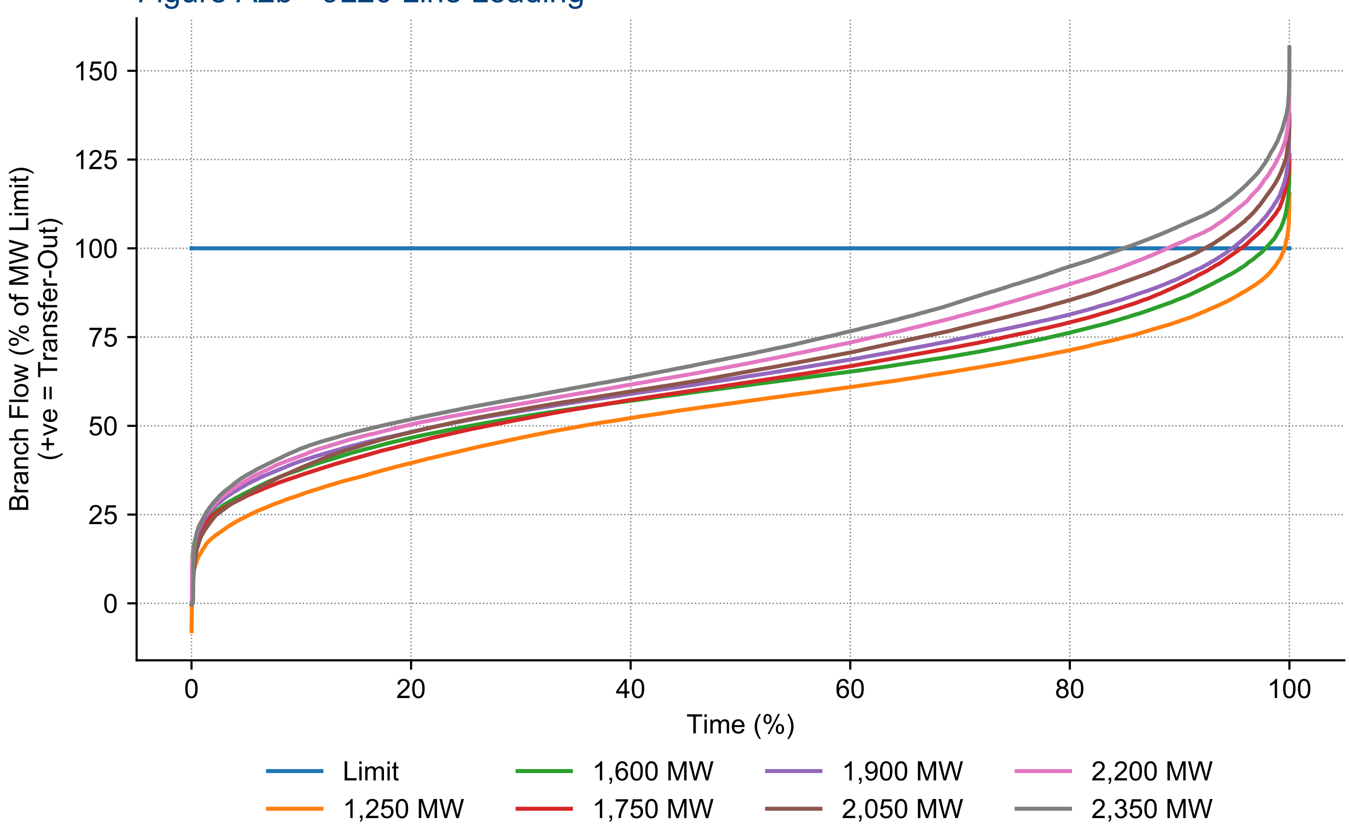


Figure A2c - 174L Line Loading

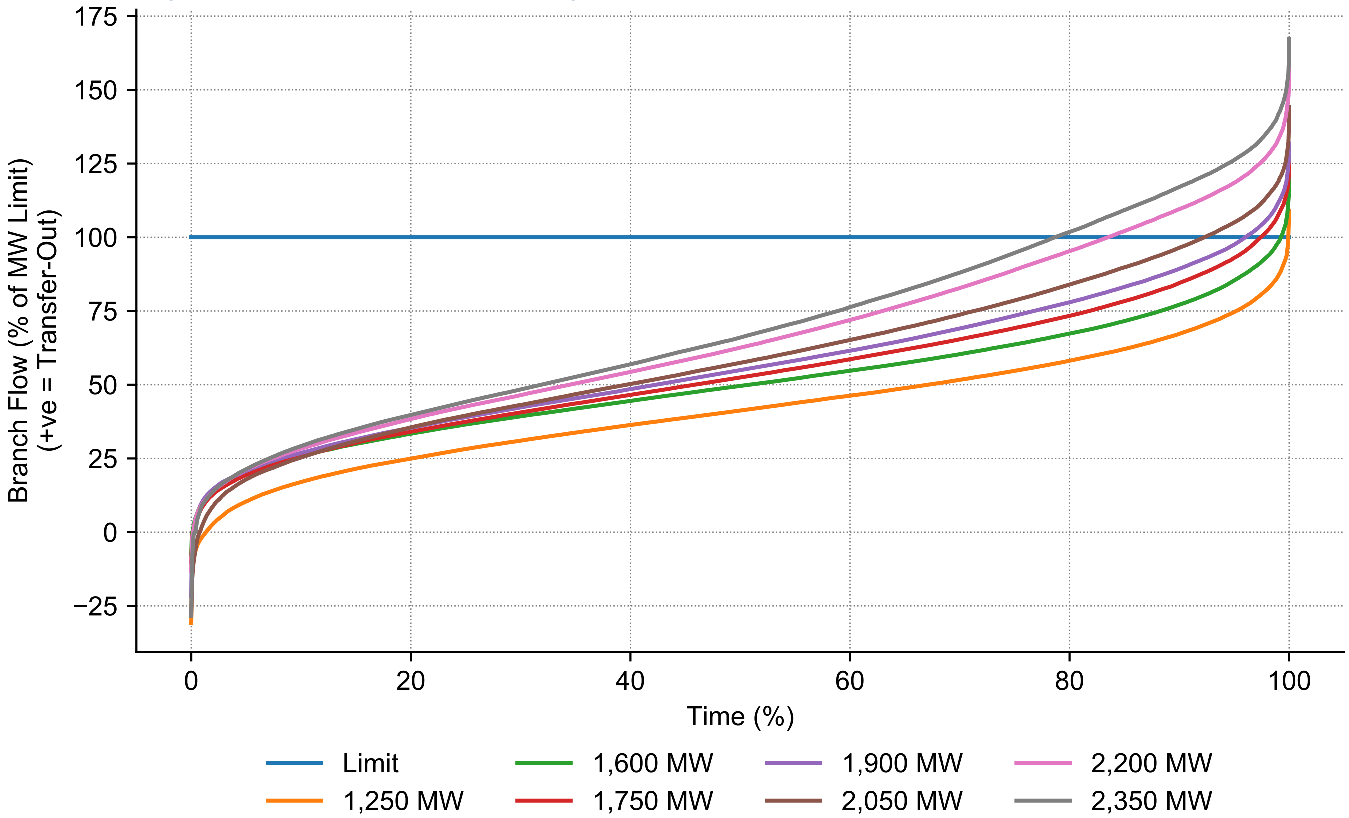


Figure A2d - 701L Line Loading

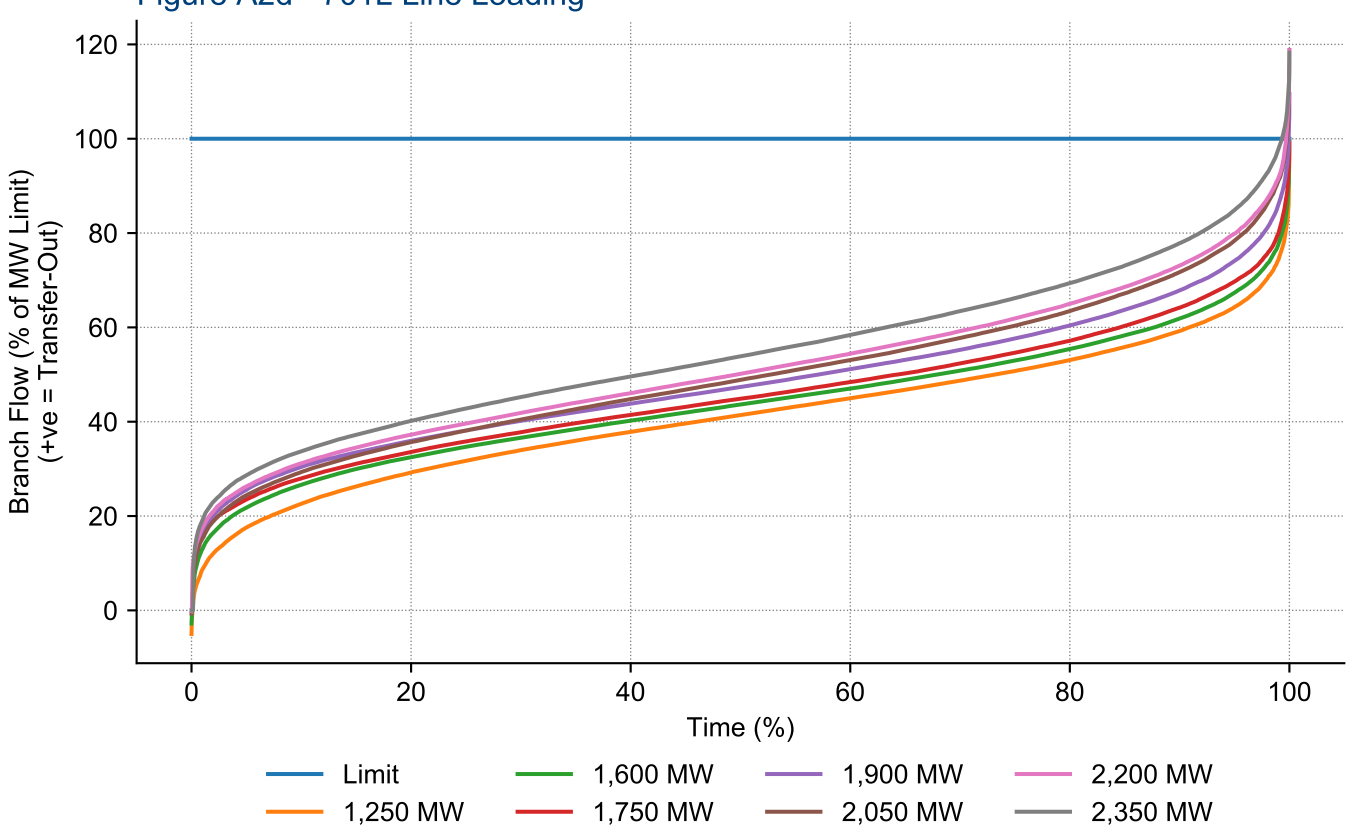


Figure A3 - Category A-MSSC Congestion Peaking Scenario in Pre-CETO

Figure A3a - 912L Line Loading

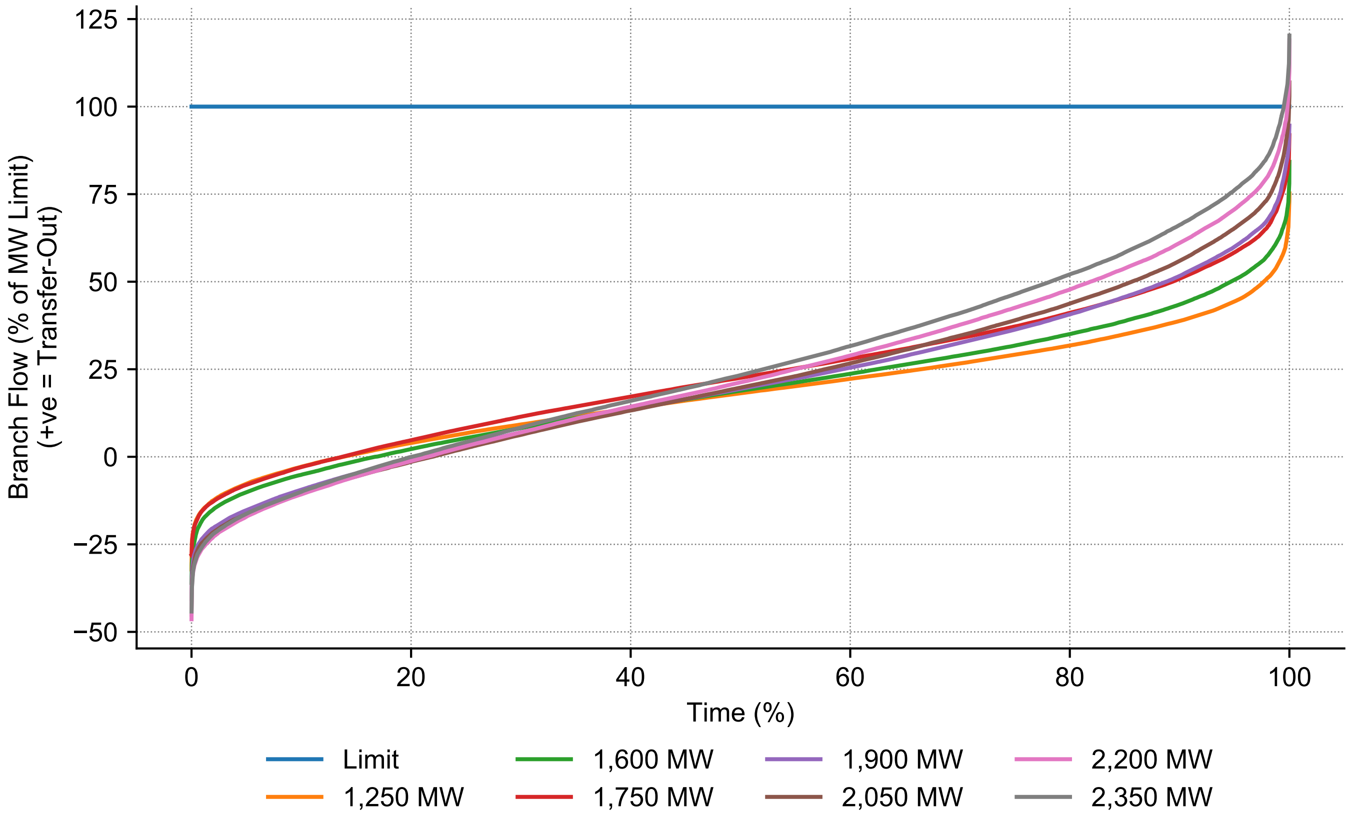


Figure A3b - 9L20 Line Loading

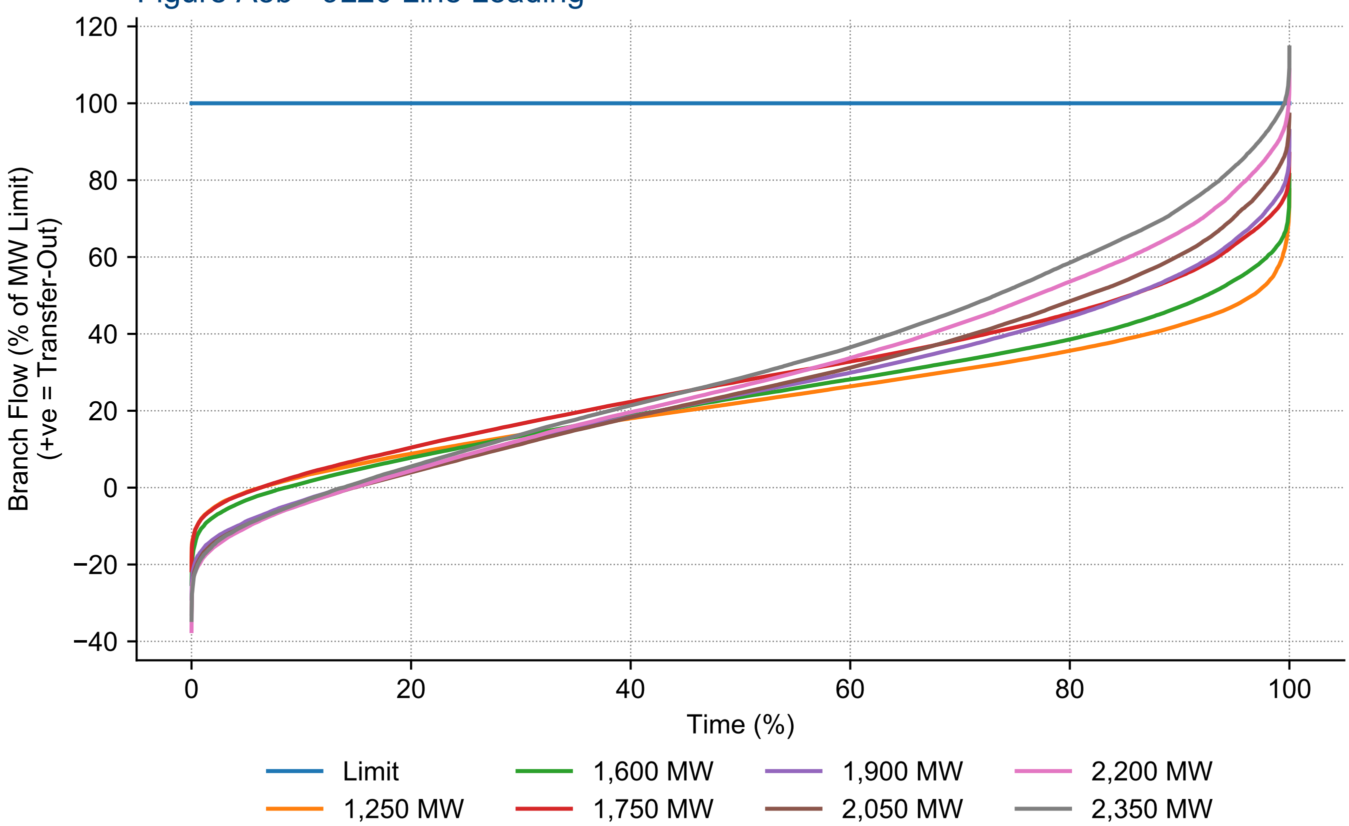


Figure A3c - 174L Line Loading

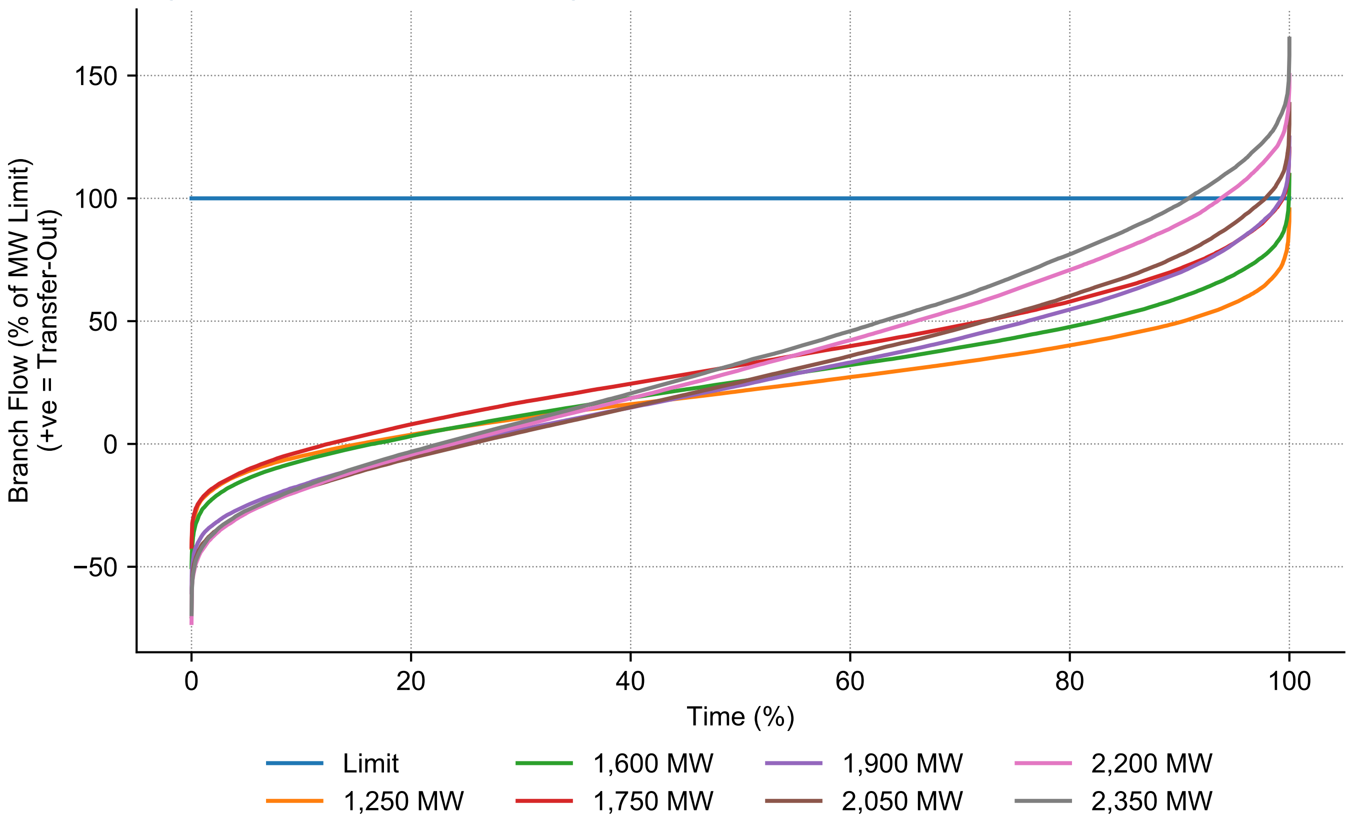


Figure A3d - 701L Line Loading

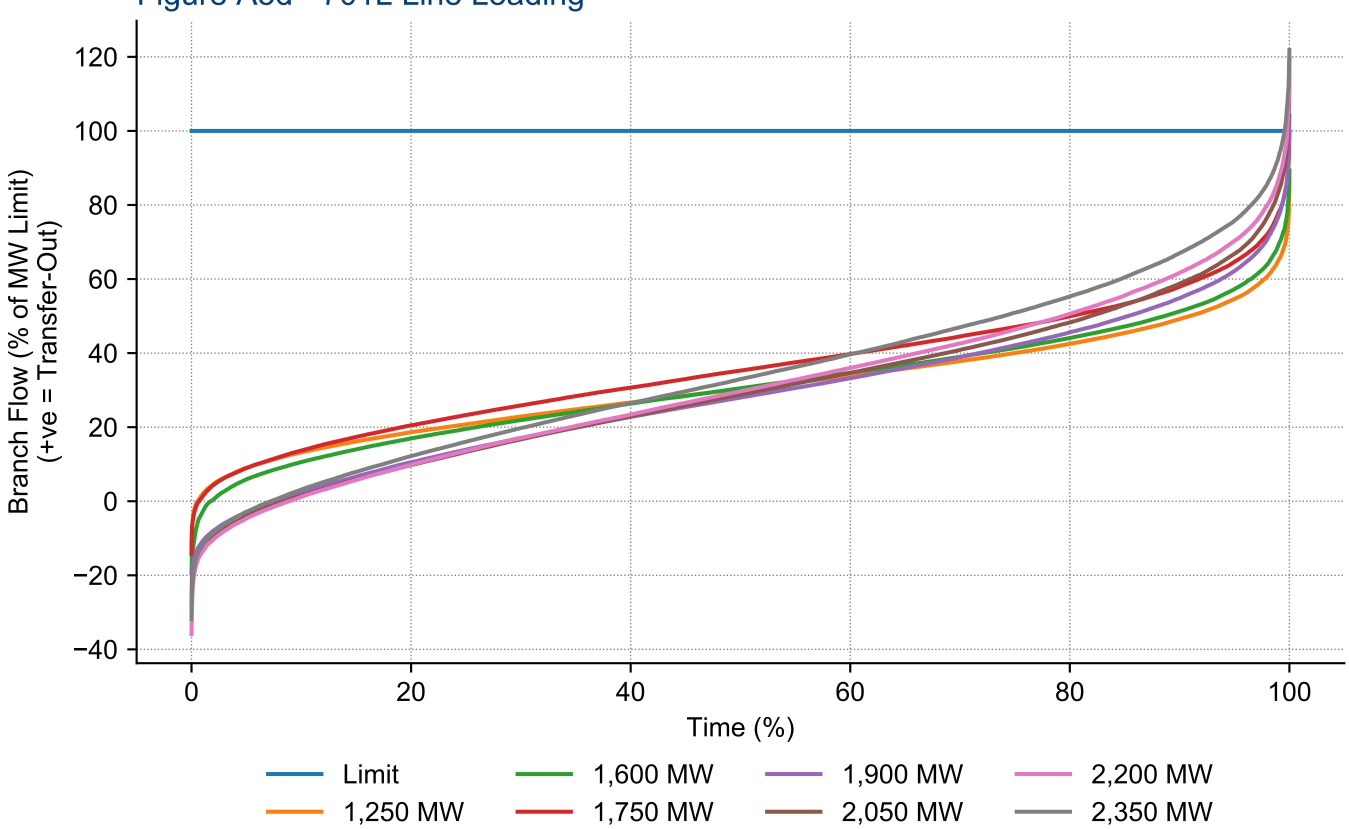


Figure A4 - Category A-MSSC Congestion
Baseload Scenario in Pre-CETO

Figure A4a - 912L Line Loading

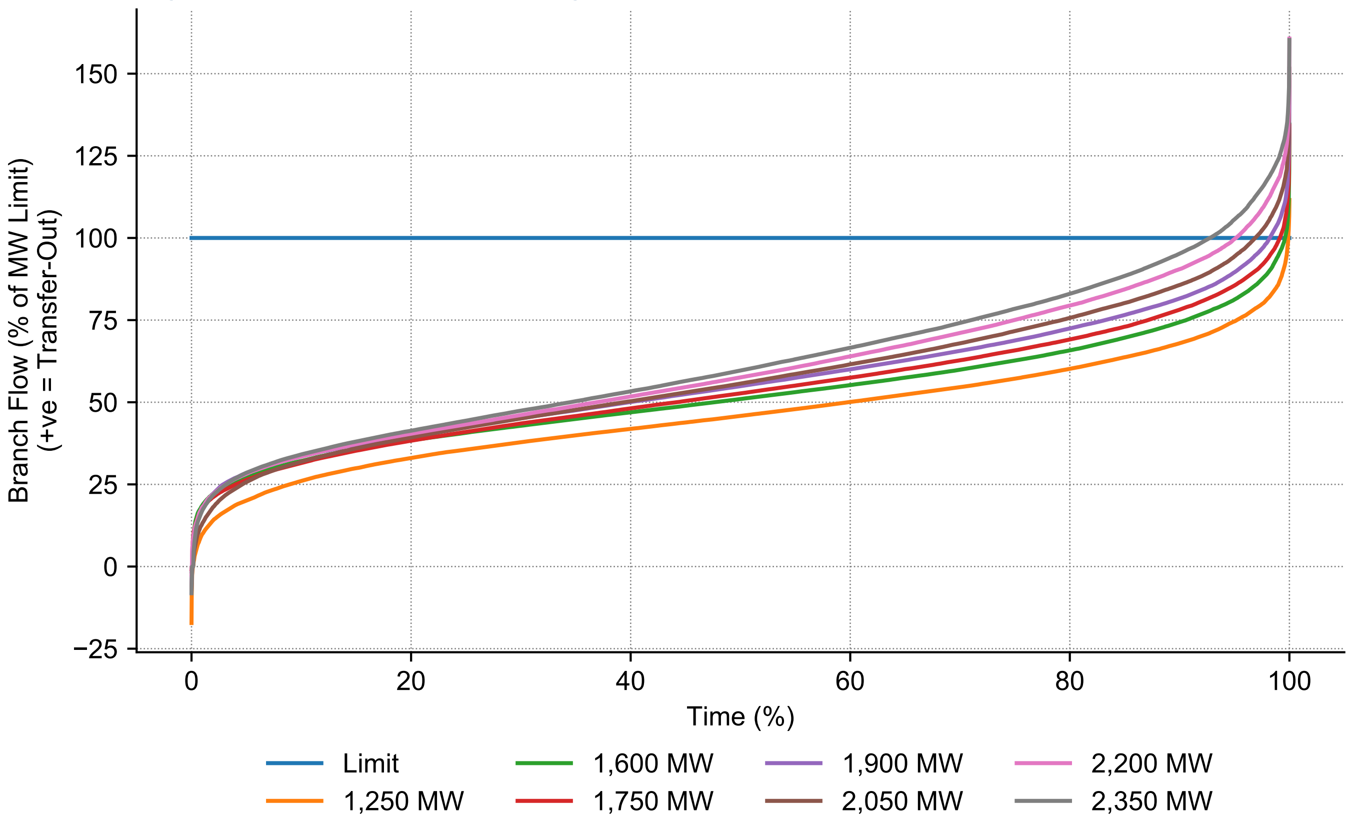


Figure A4b - 9L20 Line Loading

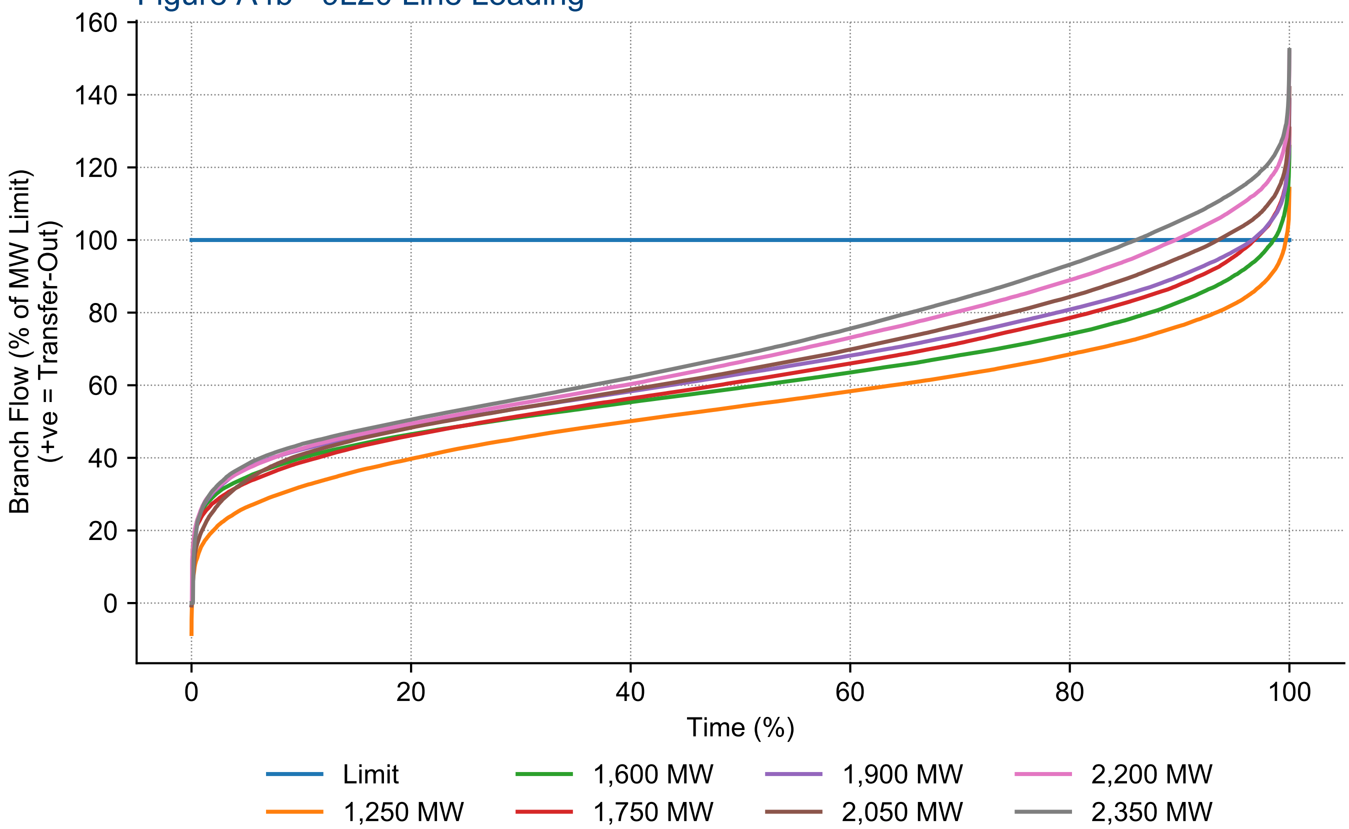


Figure A4c - 174L Line Loading

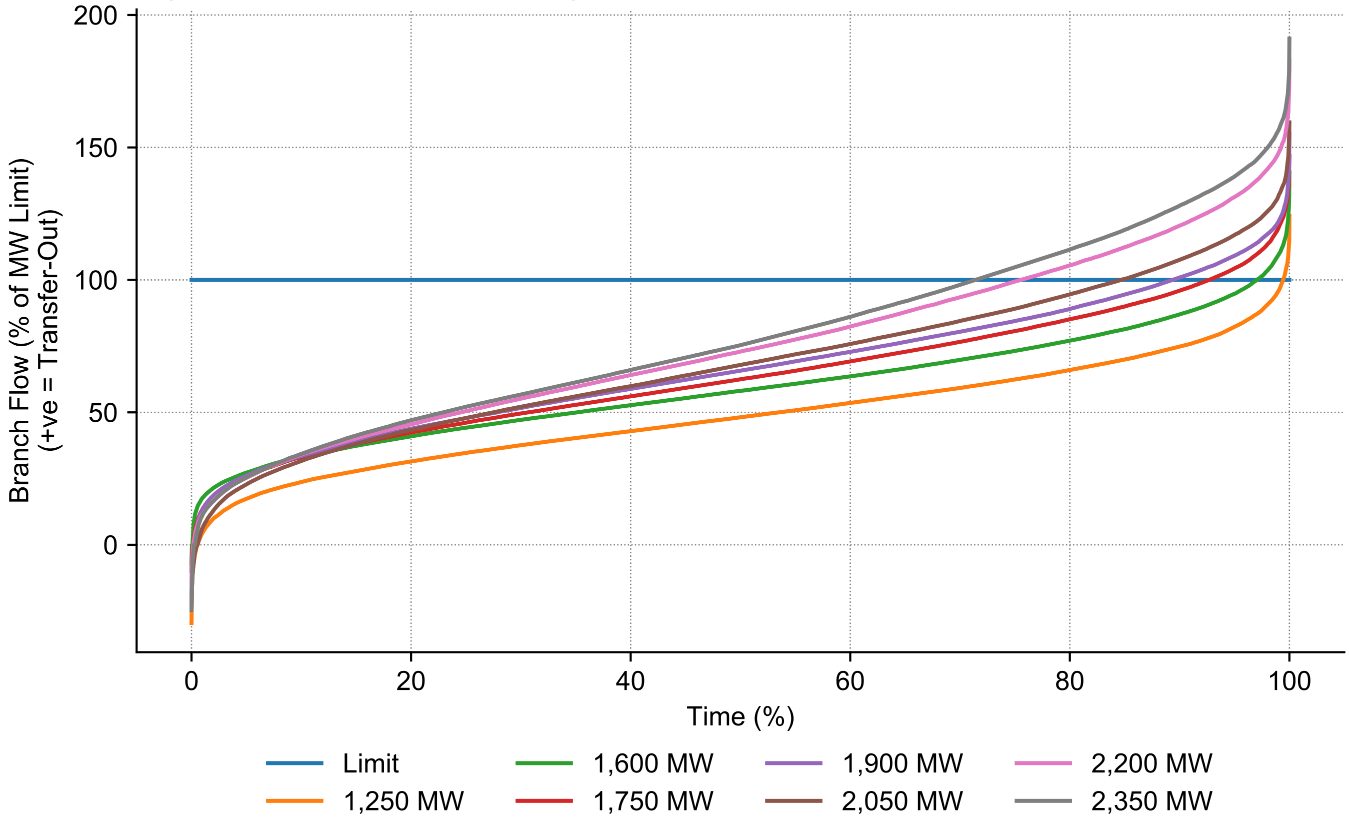


Figure A4d - 701L Line Loading

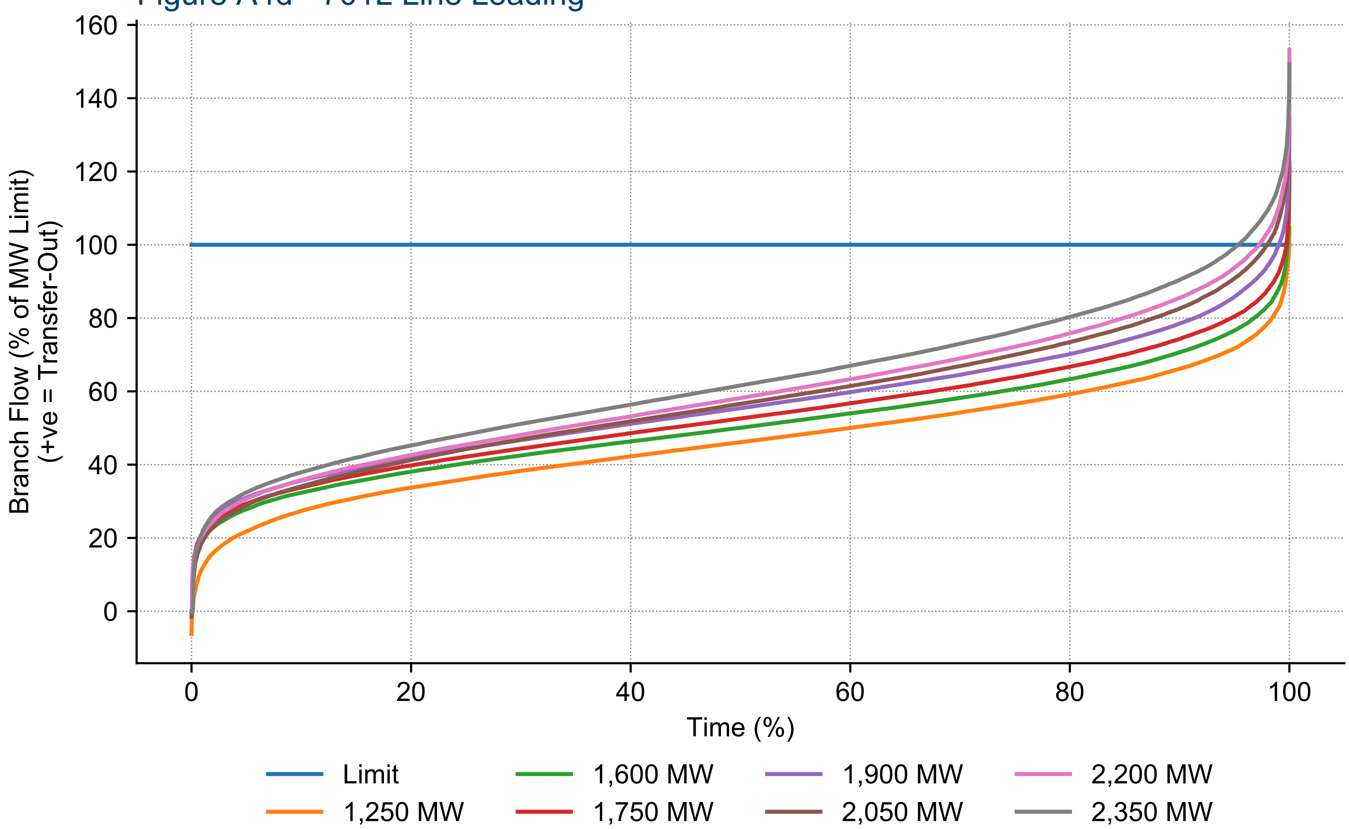


Figure A5 - Category A Congestion
Peaking Scenario in Post-CETO, First Circuit

Figure A5a - 912L Line Loading

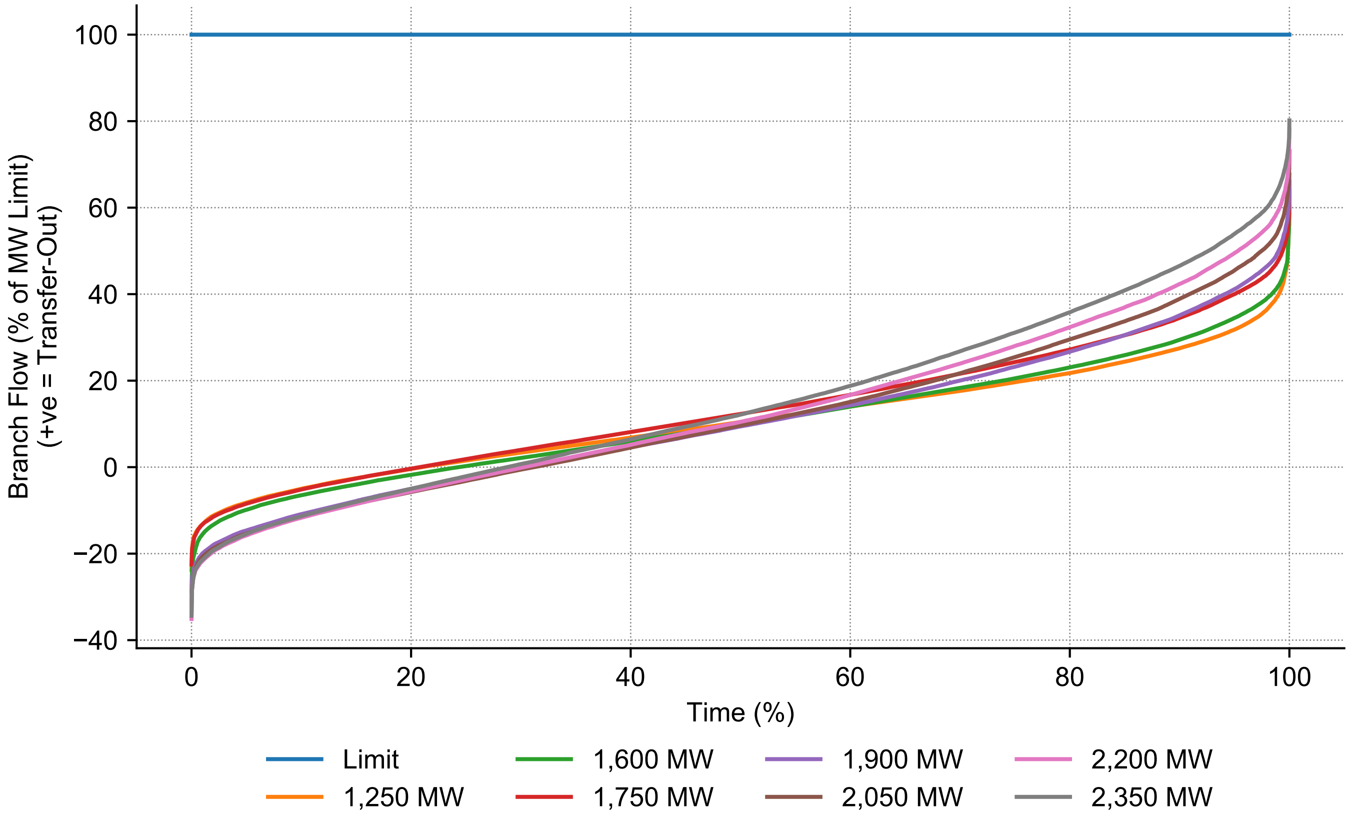


Figure A5b - 9L20 Line Loading

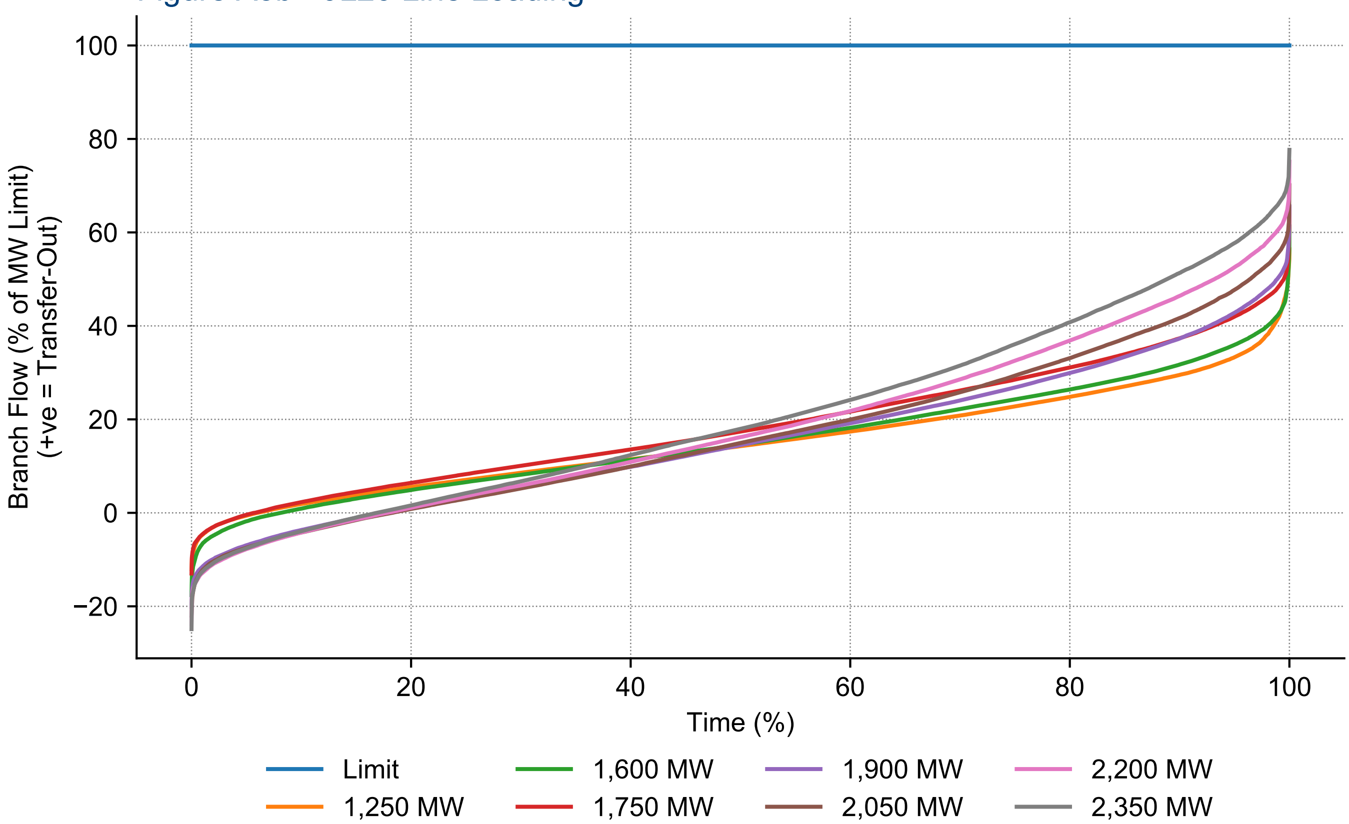


Figure A5c - 174L Line Loading

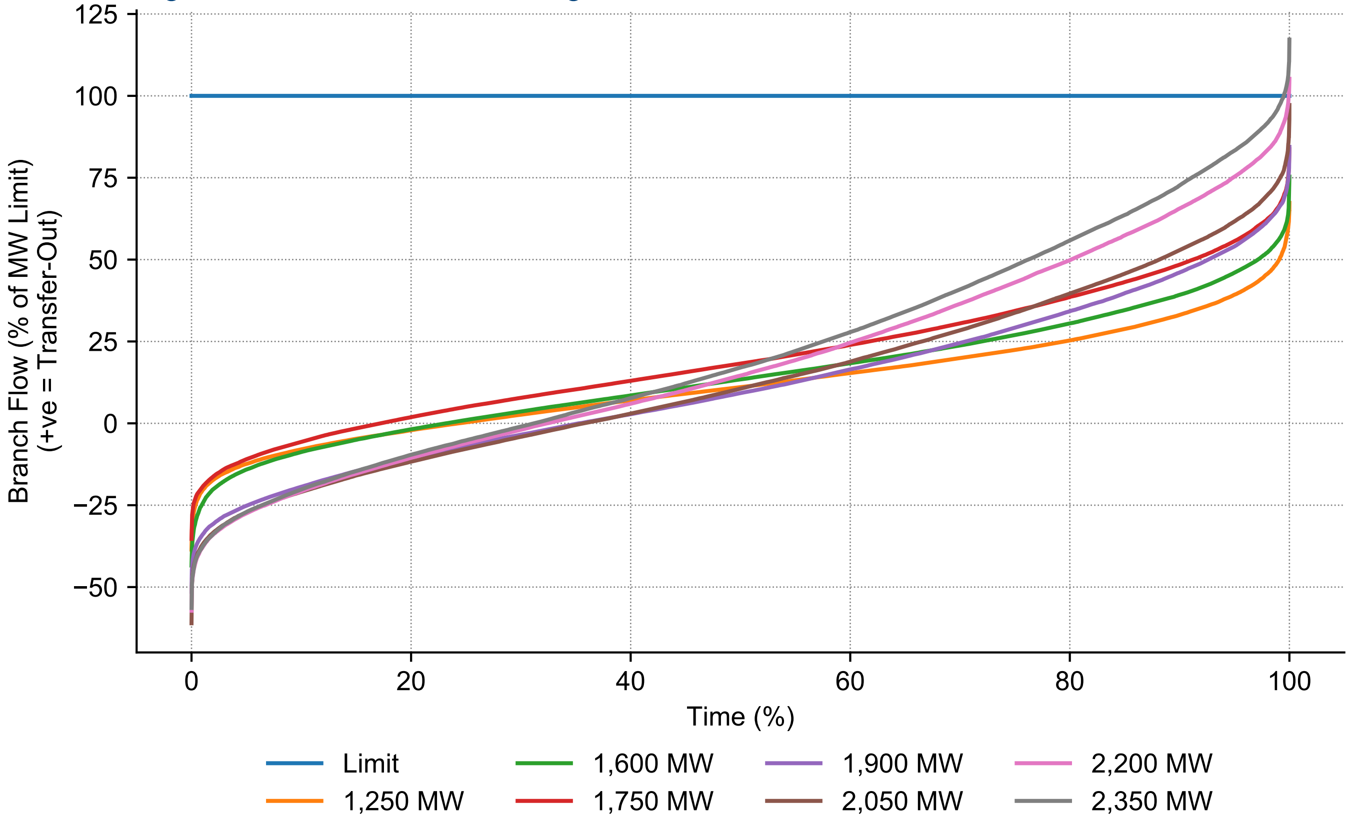


Figure A5d - 701L Line Loading

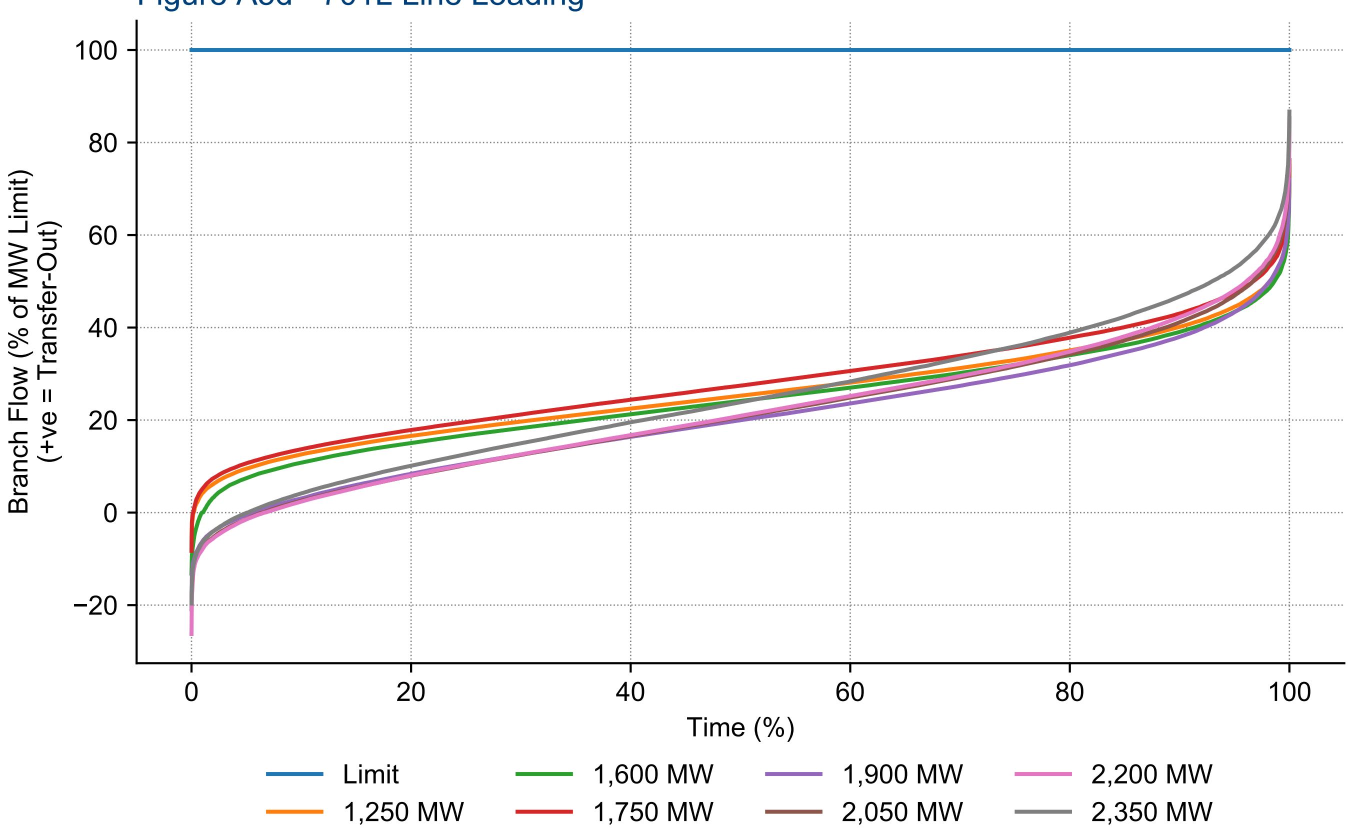


Figure A6 - Category A Congestion
Baseload Scenario in Post-CETO, First Circuit

Figure A6a - 912L Line Loading

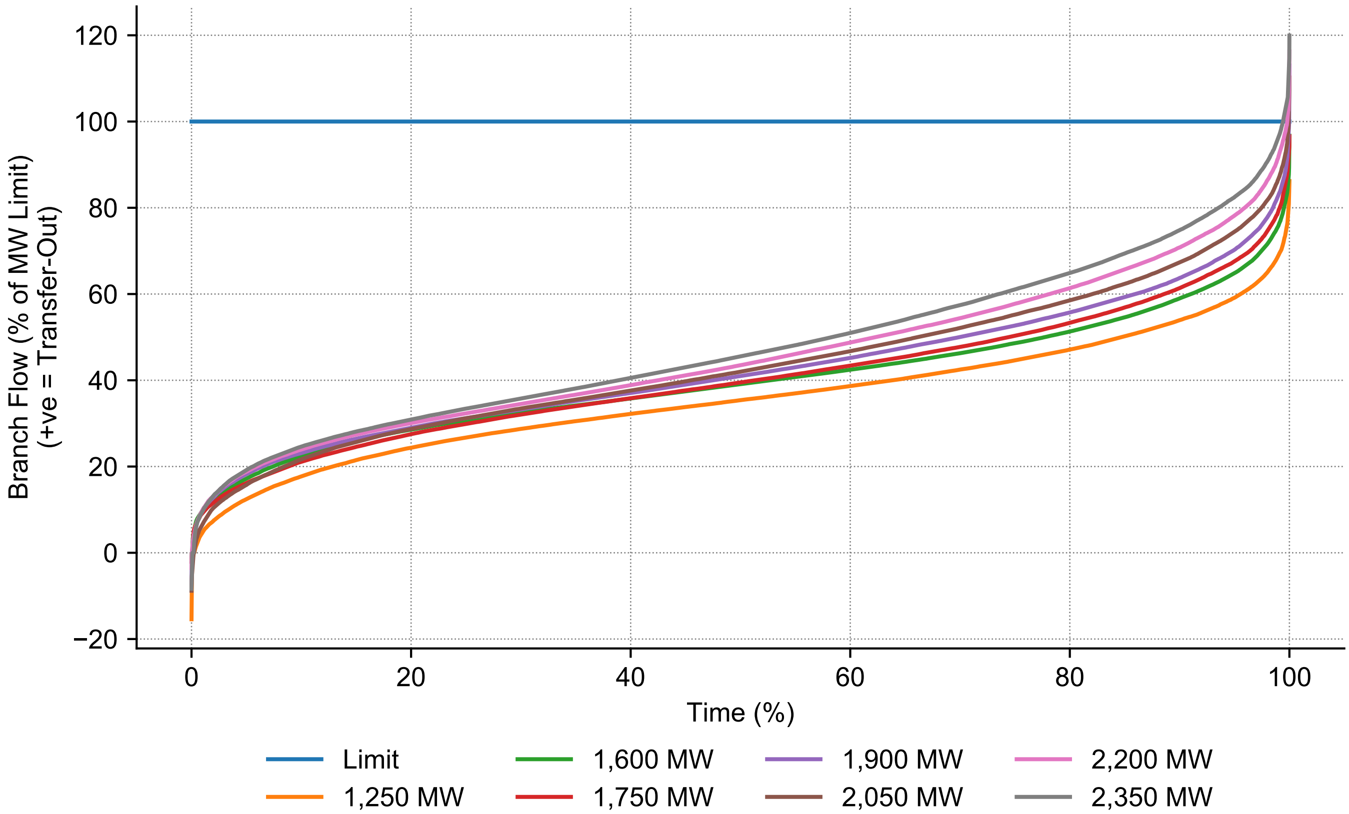


Figure A6b - 9L20 Line Loading

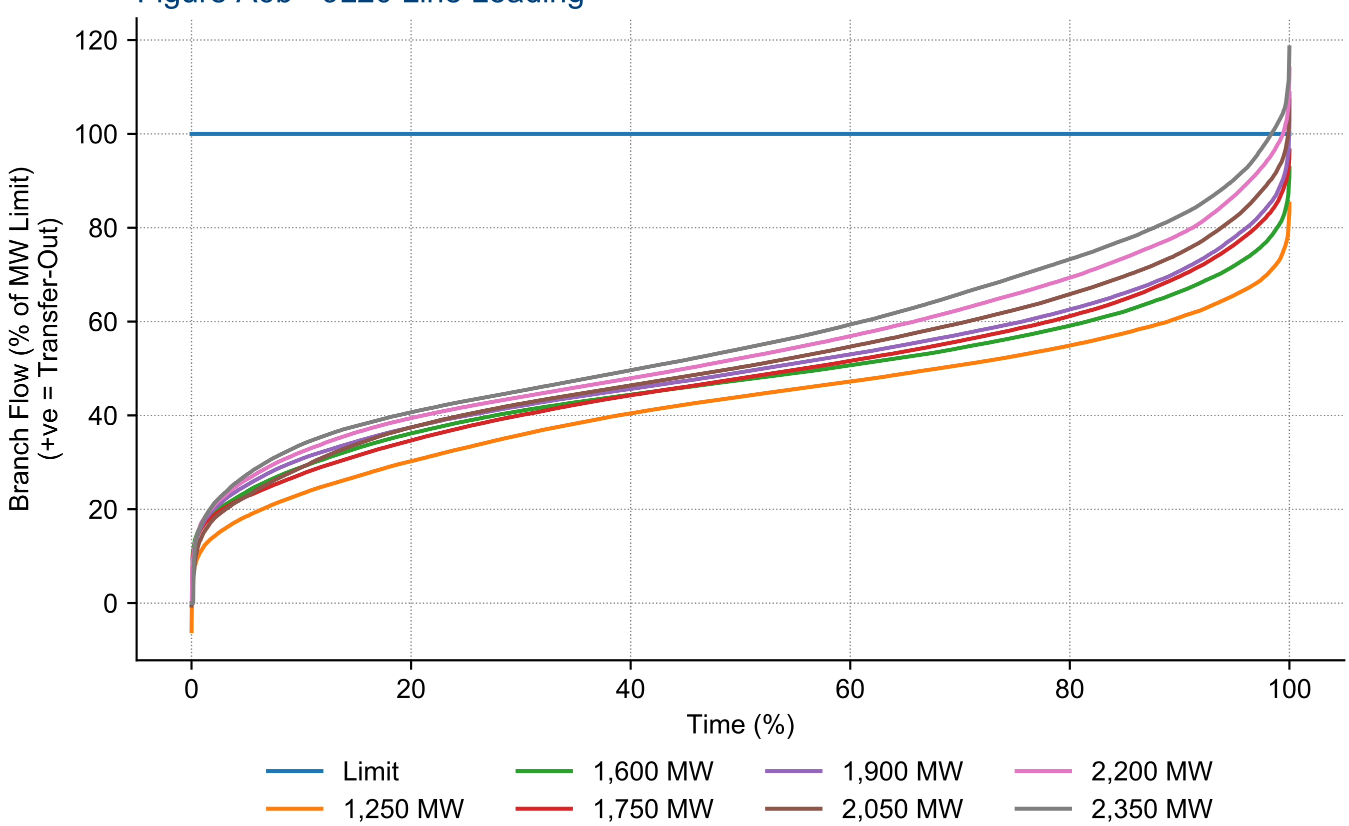


Figure A6c - 174L Line Loading

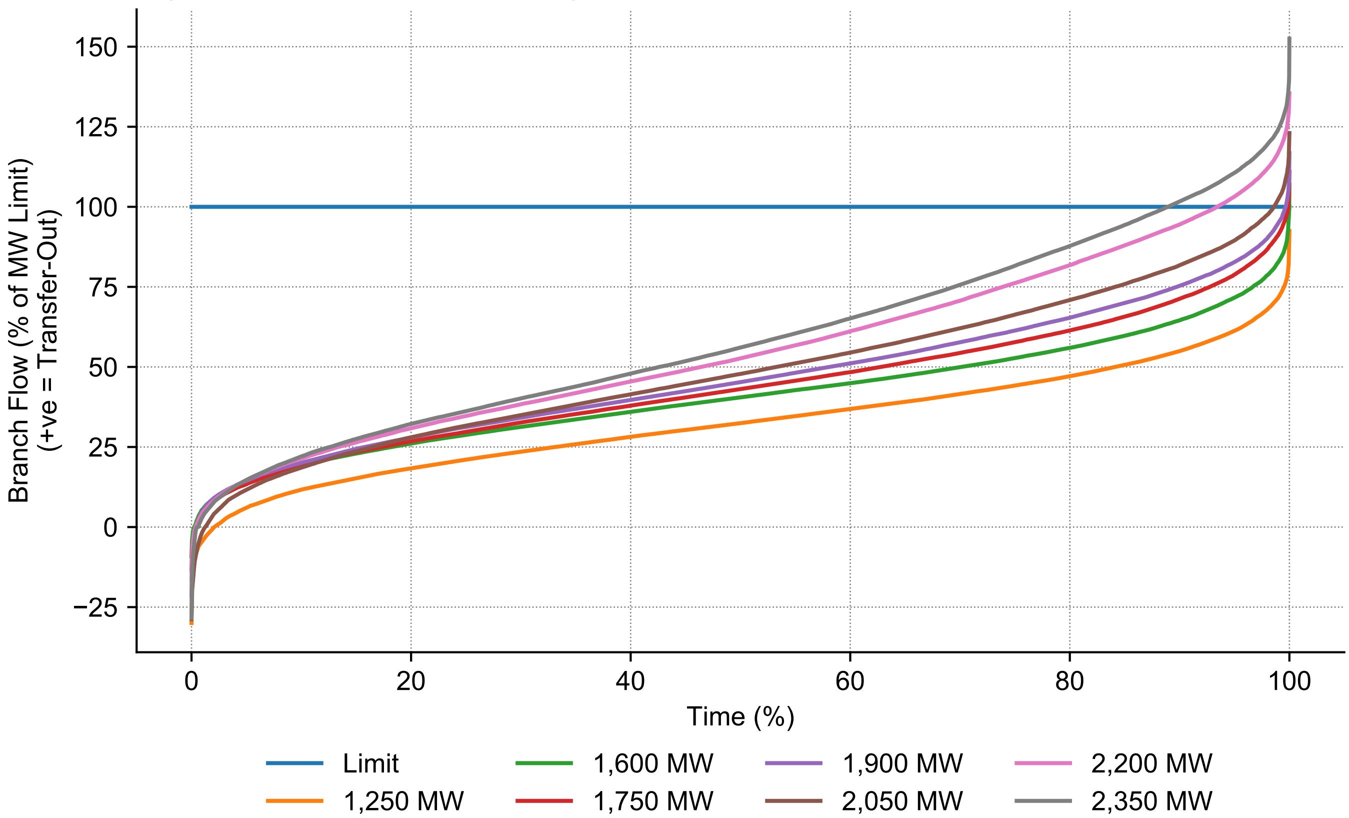


Figure A6d - 701L Line Loading

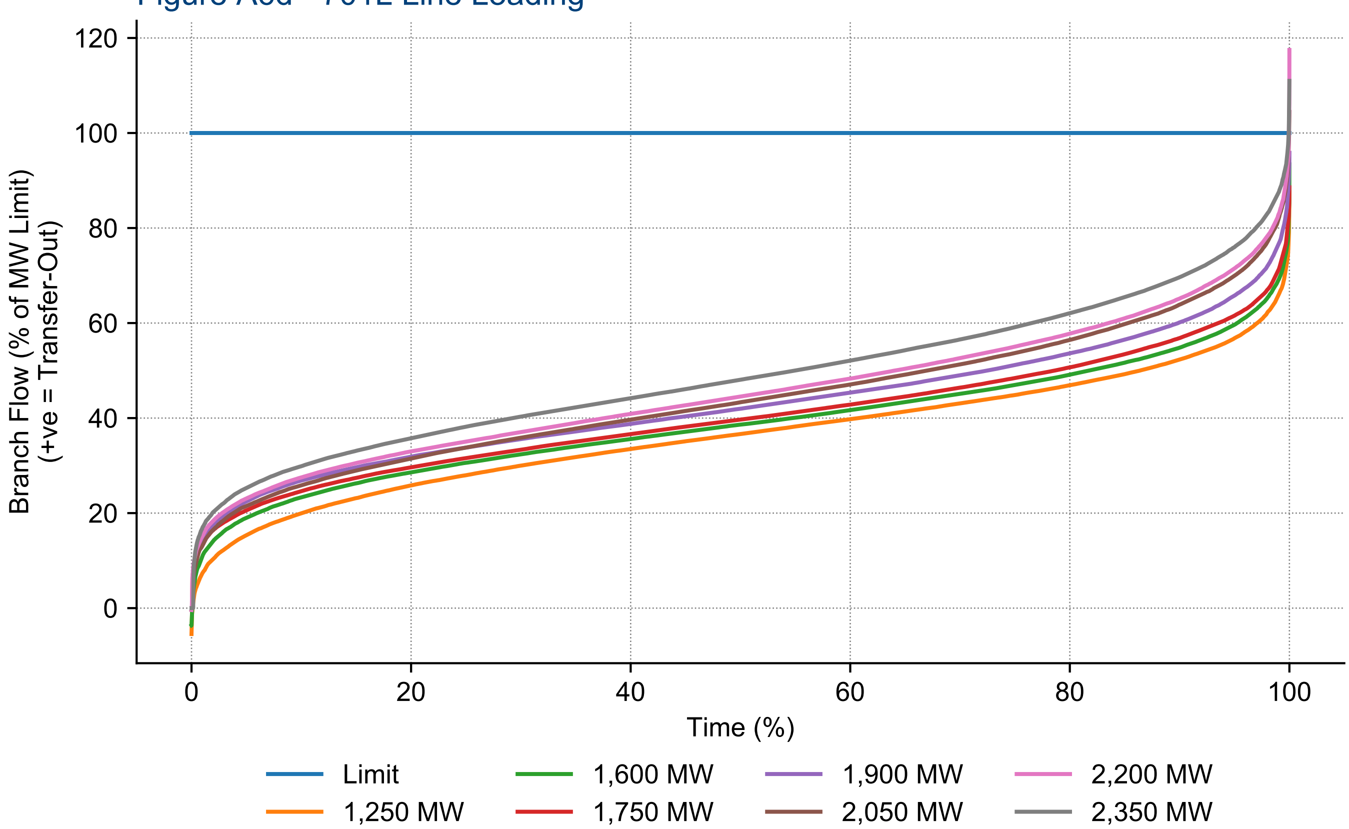


Figure A7 - Category A-MSSC Congestion
Peaking Scenario in Post-CETO, First Circuit

Figure A7a - 912L Line Loading

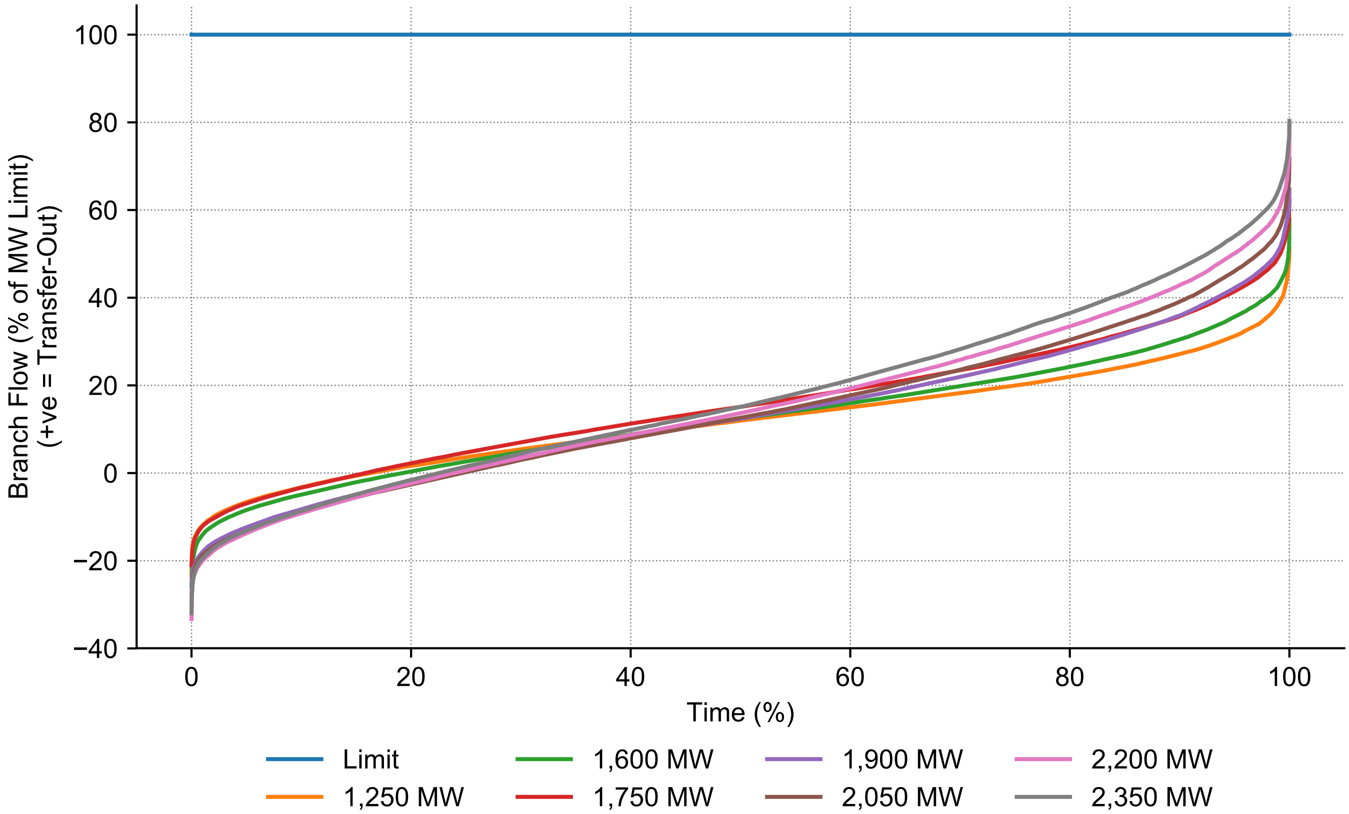


Figure A7b - 9L20 Line Loading

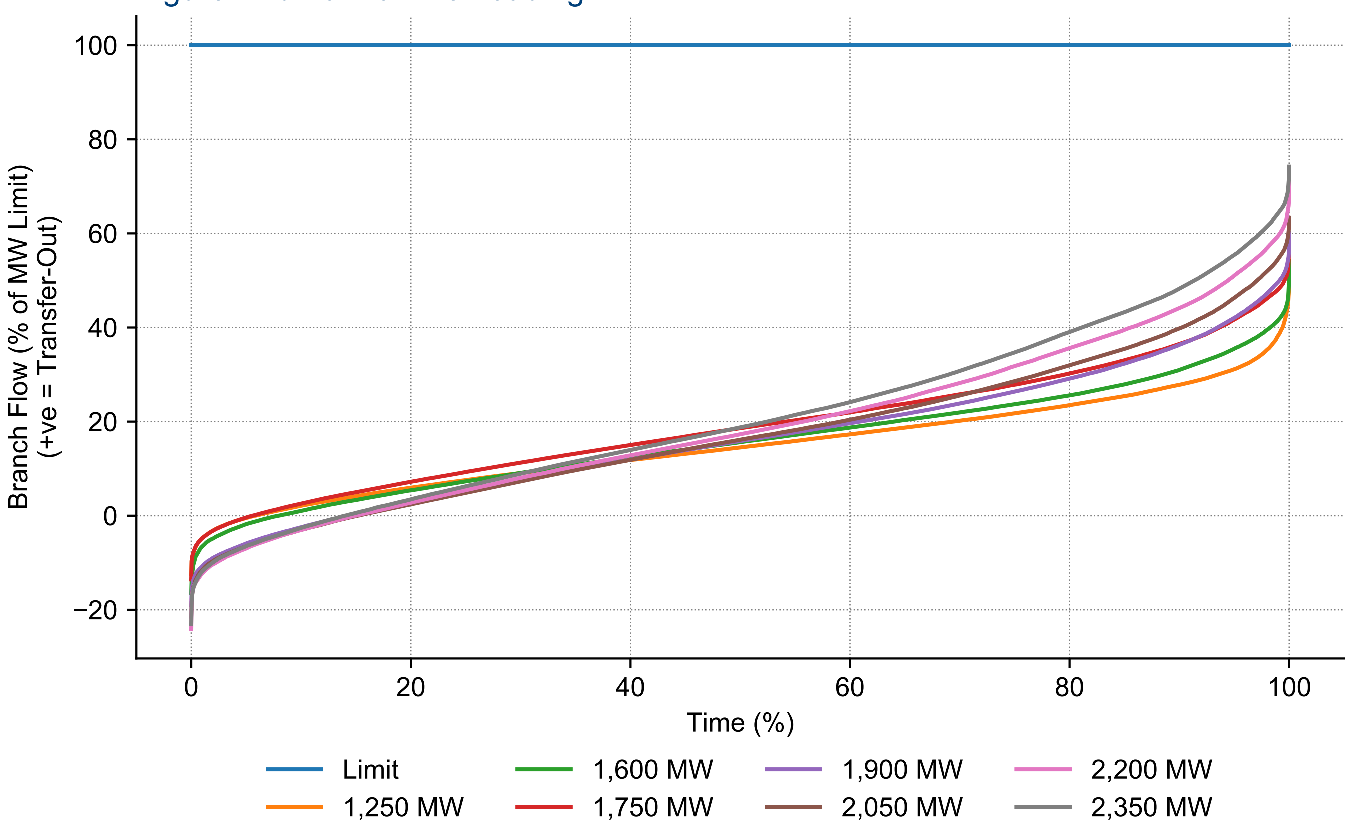


Figure A7c - 174L Line Loading

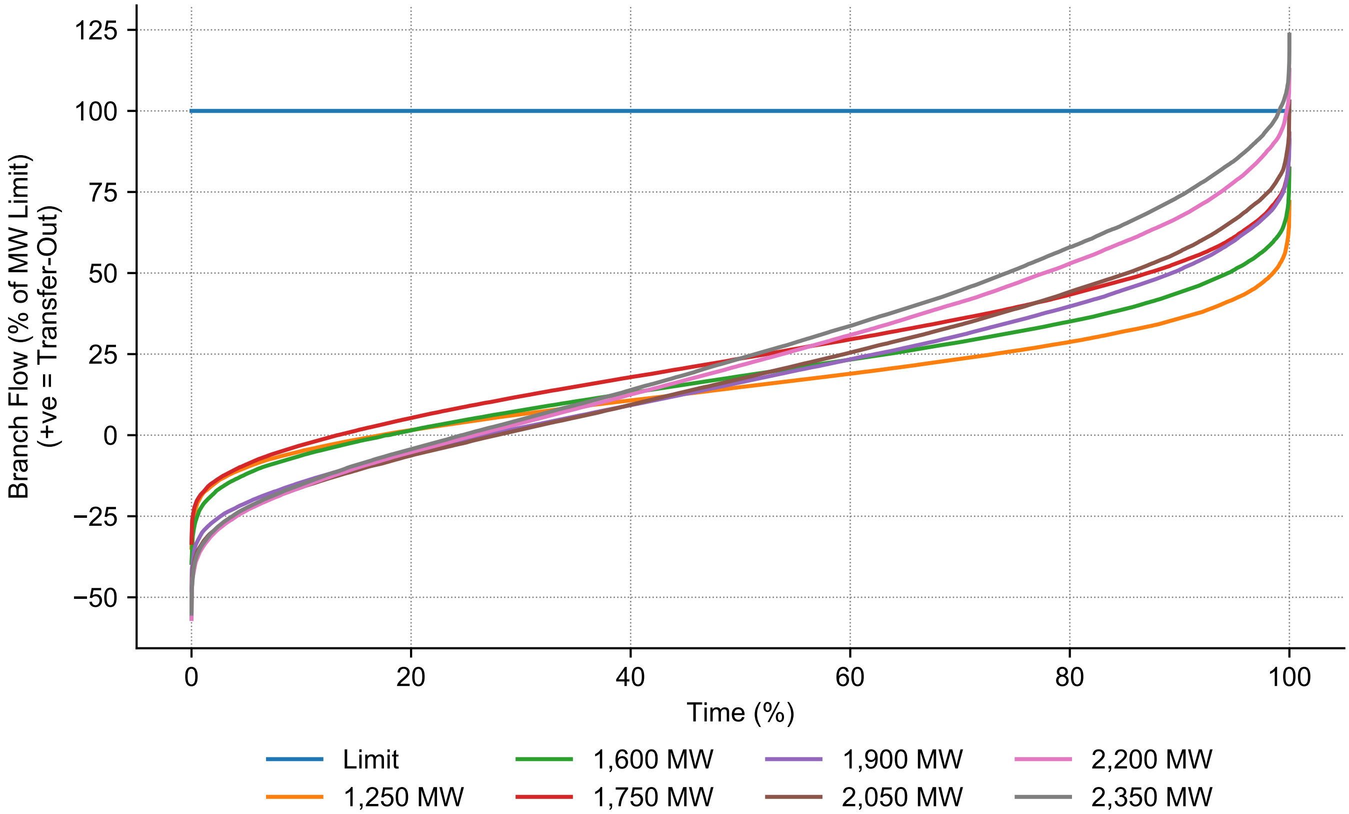


Figure A7d - 701L Line Loading

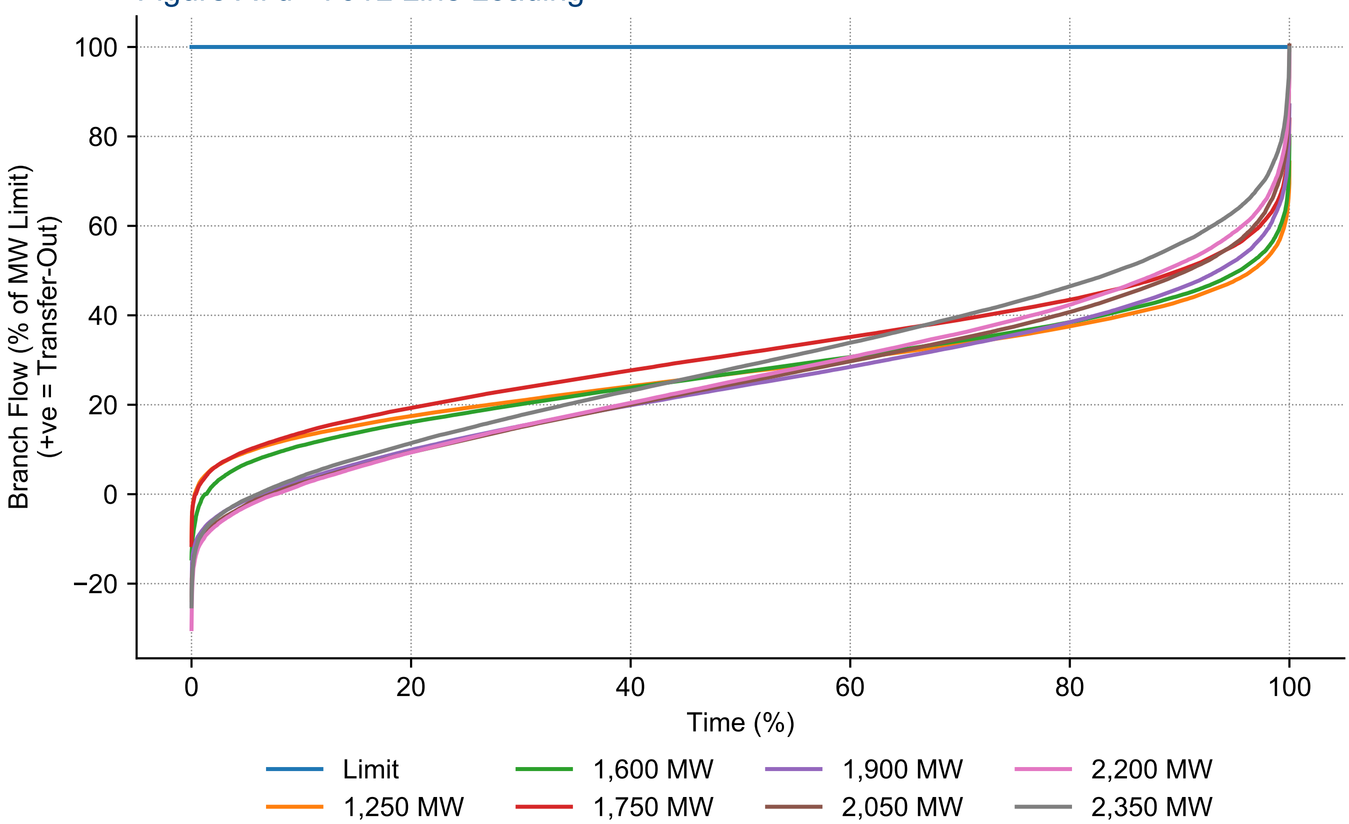


Figure A8 - Category A-MSSC Congestion
Baseload Scenario in Post-CETO, First Circuit

Figure A8a - 912L Line Loading

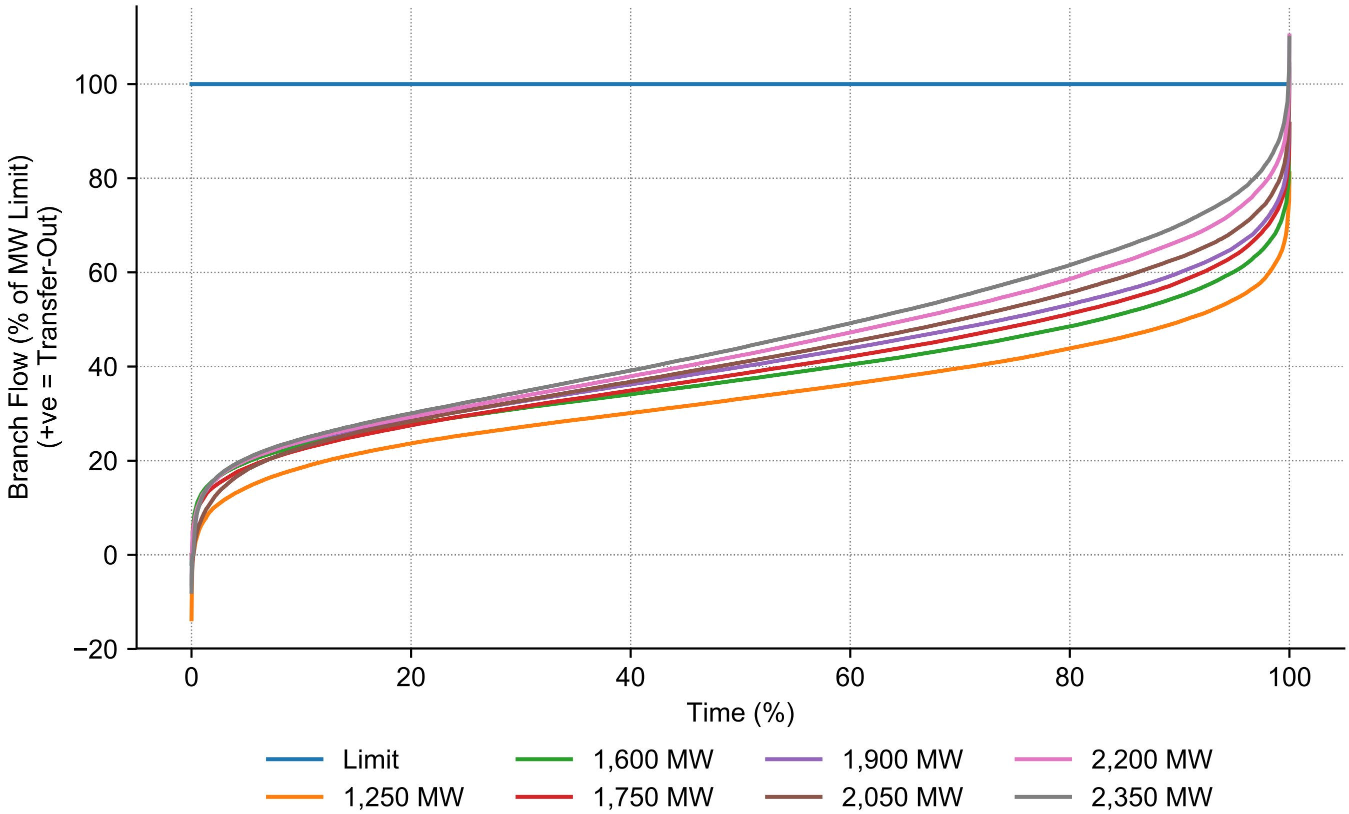


Figure A8b - 9L20 Line Loading

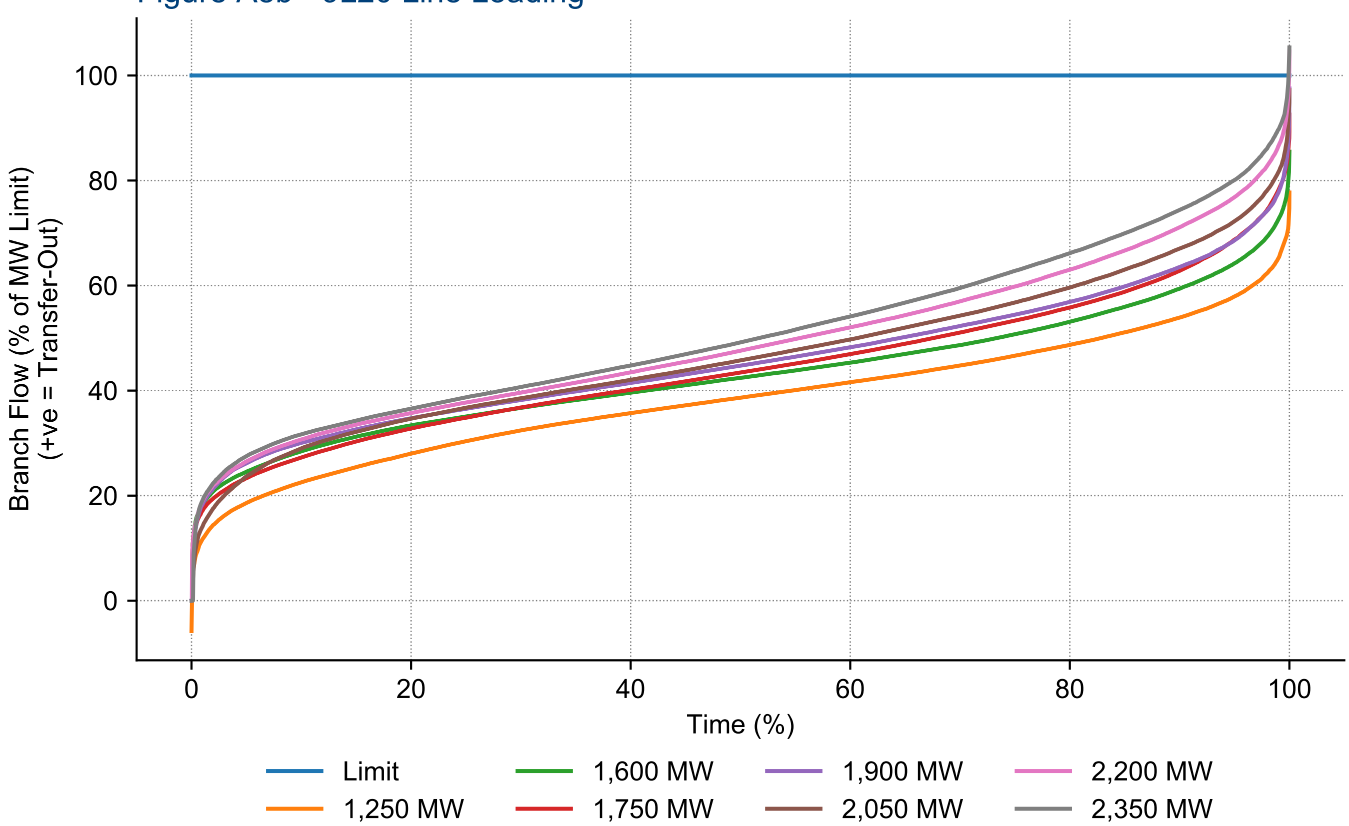


Figure A8c - 174L Line Loading

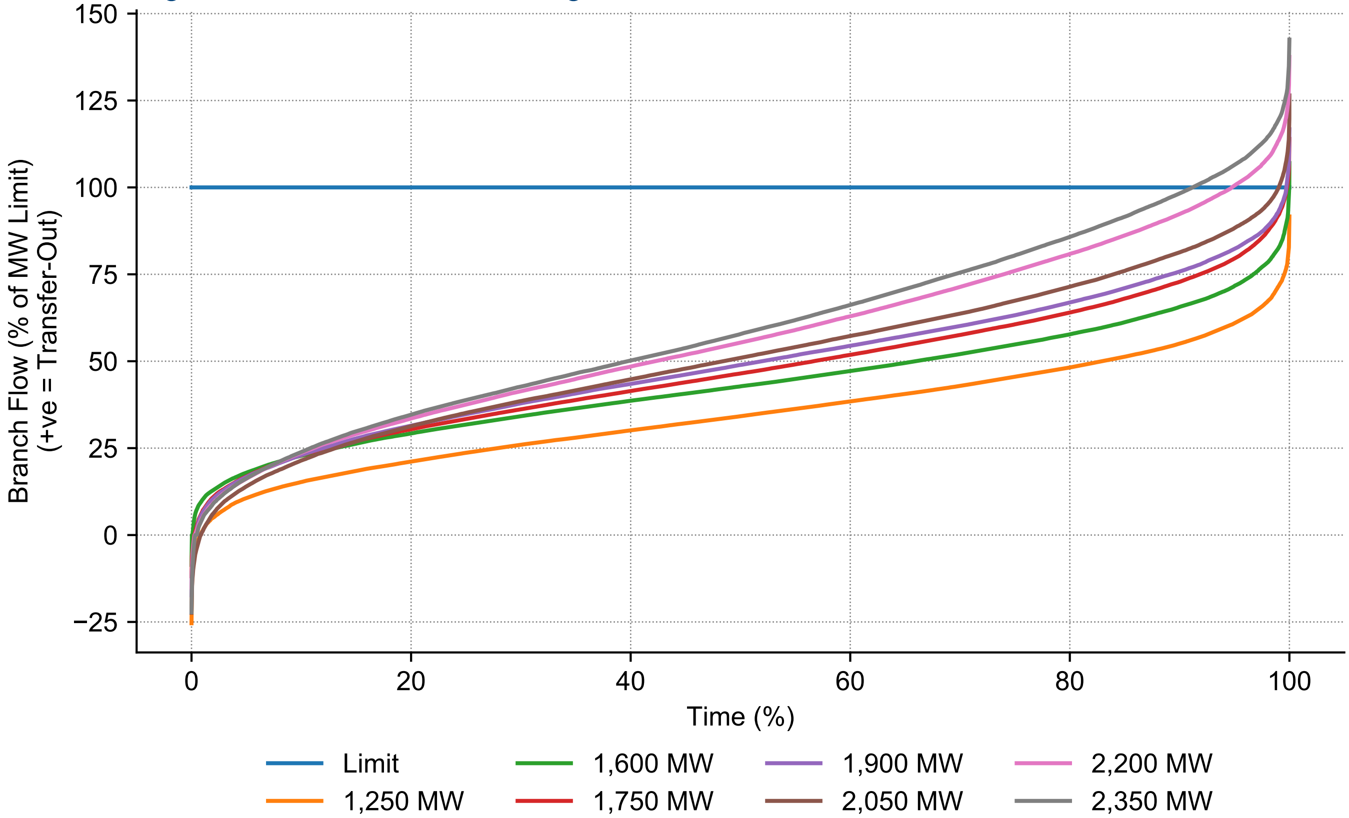
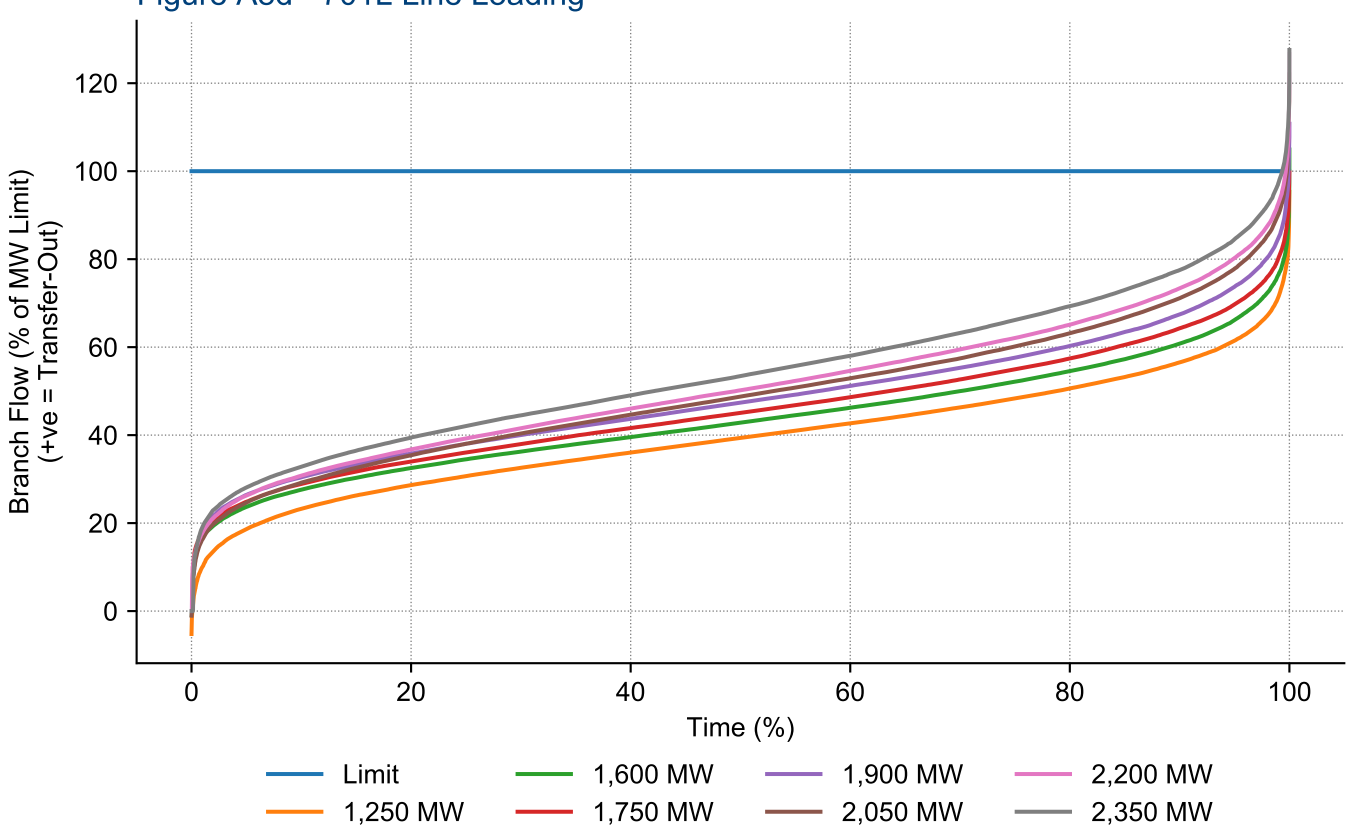


Figure A8d - 701L Line Loading



Attachment B

Flow Density Plots

Figure B1 - Category A Congestion for Pre-CETO

Figure B1a - 912L Line Loading

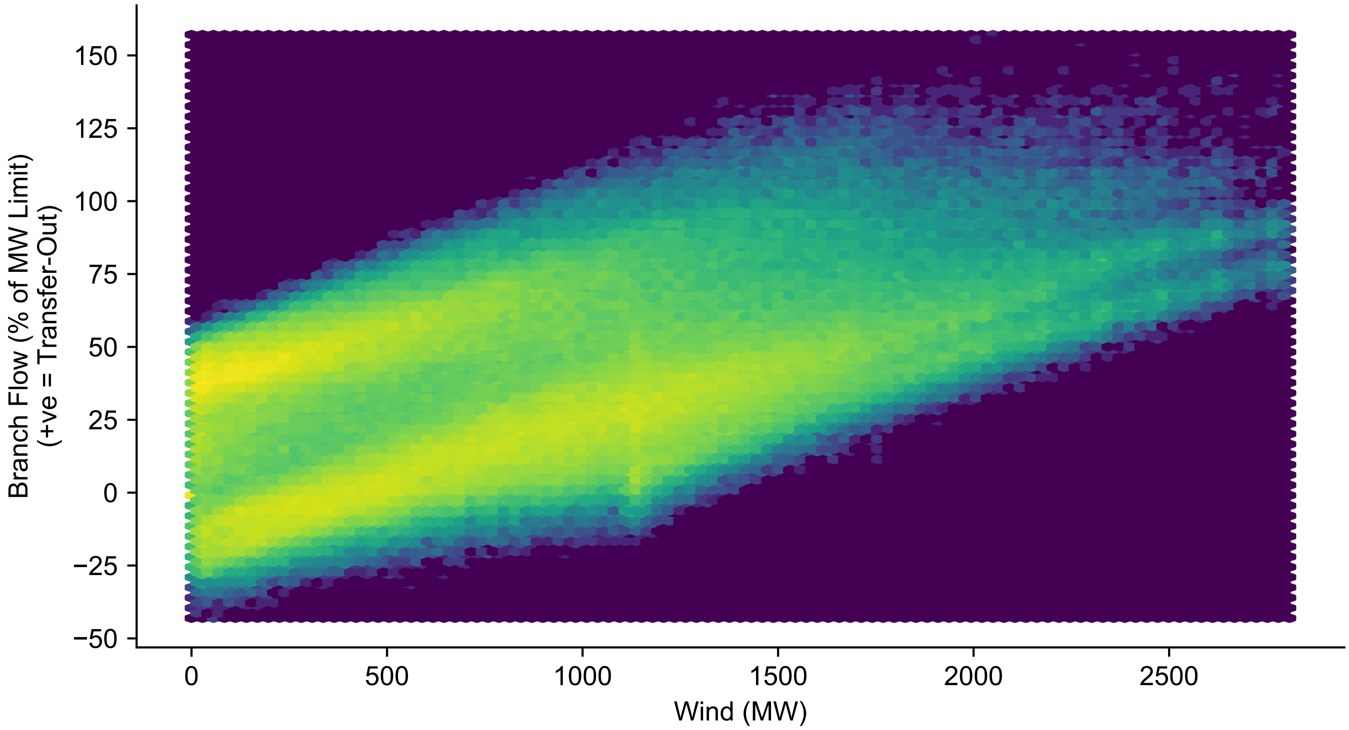


Figure B1b - 9L20 Line Loading

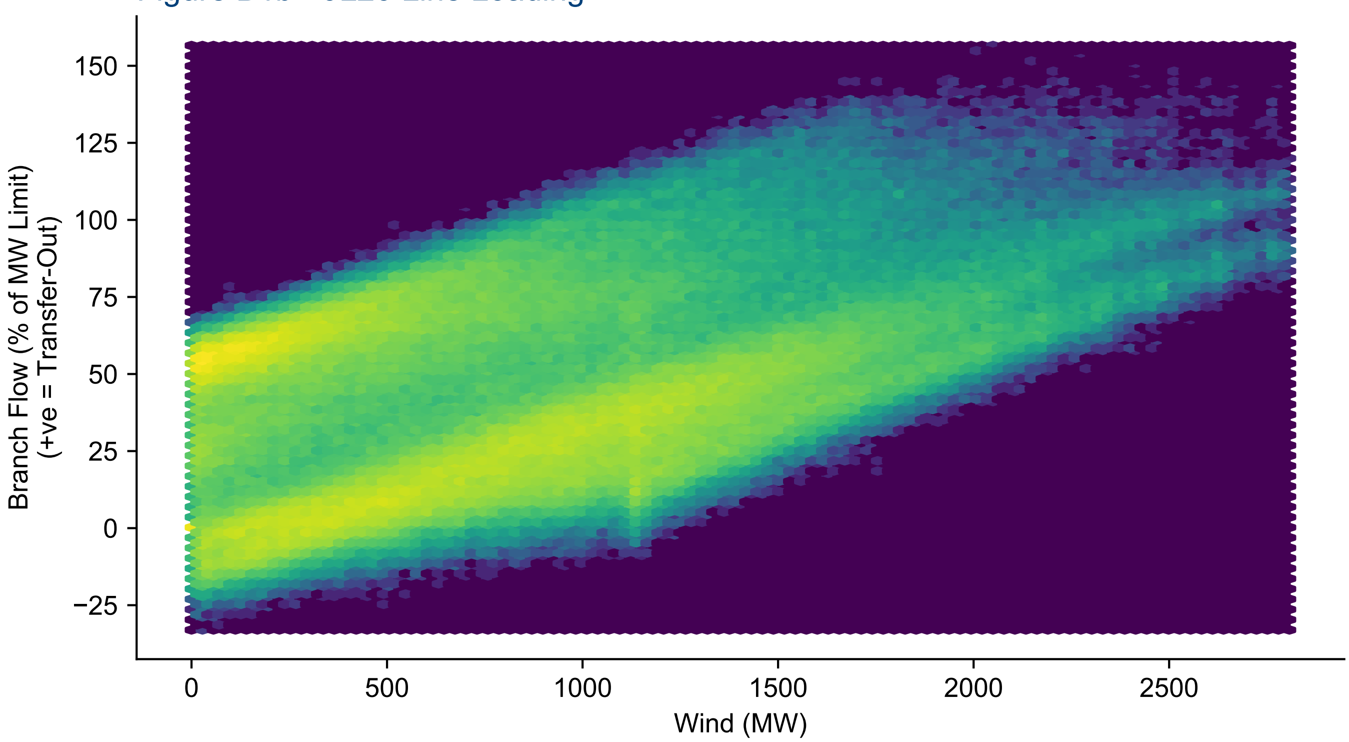


Figure B1c - 174L Line Loading

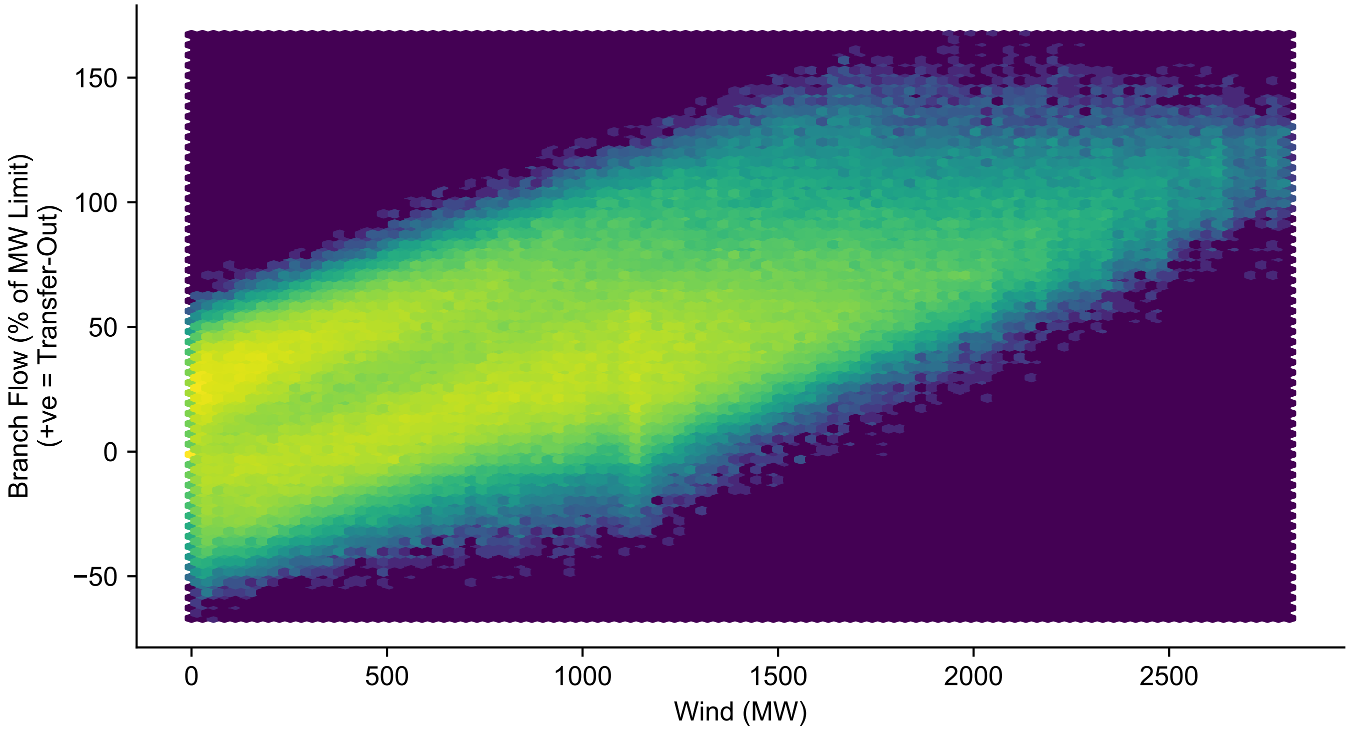


Figure B1d - 701L Line Loading

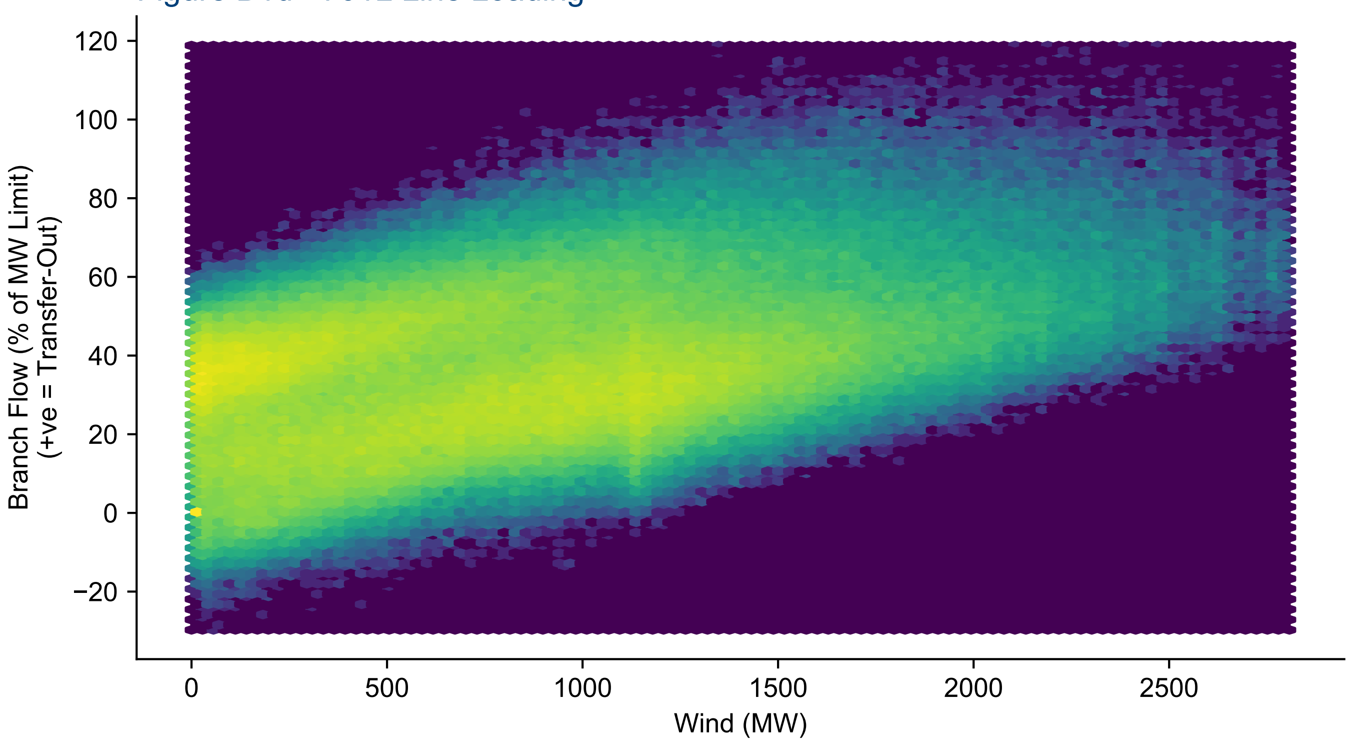


Figure B2 - Category A-MSSC Congestion for Pre-CETO

Figure B2a - 912L Line Loading

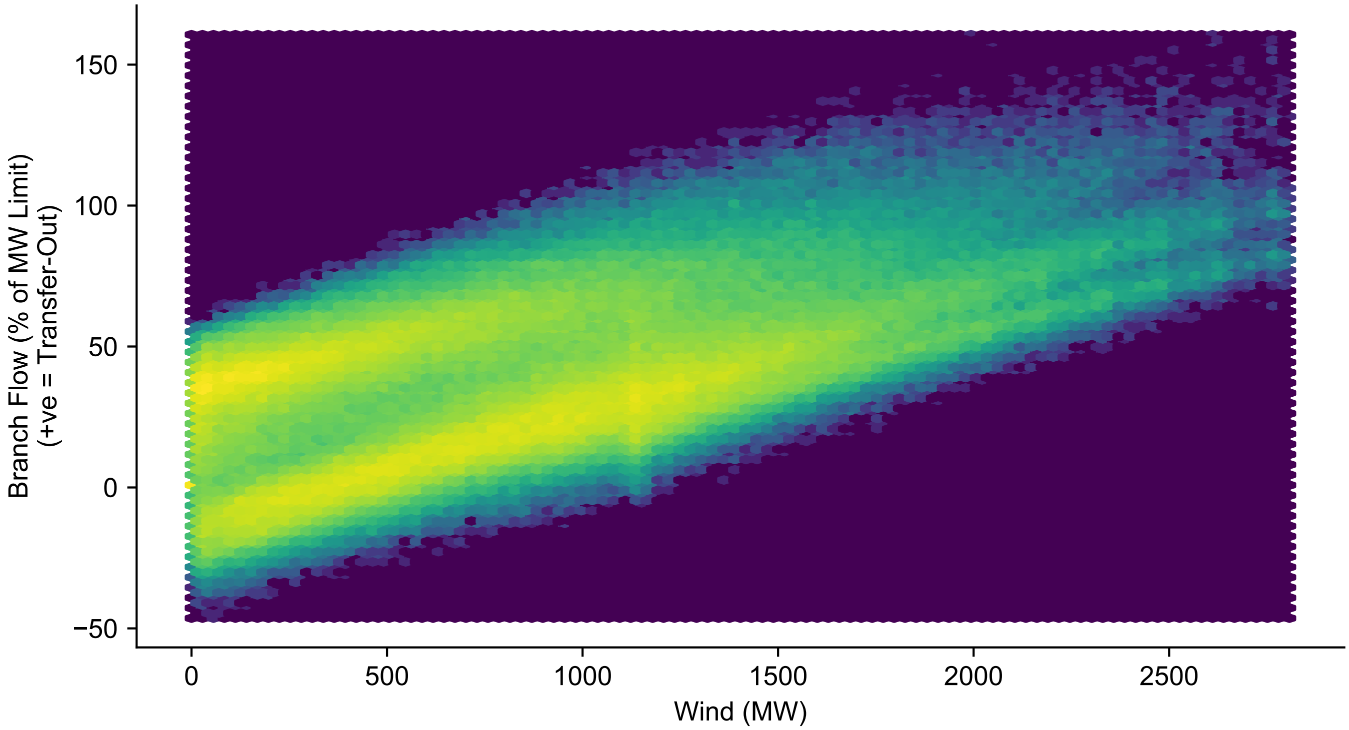


Figure B2b - 9L20 Line Loading

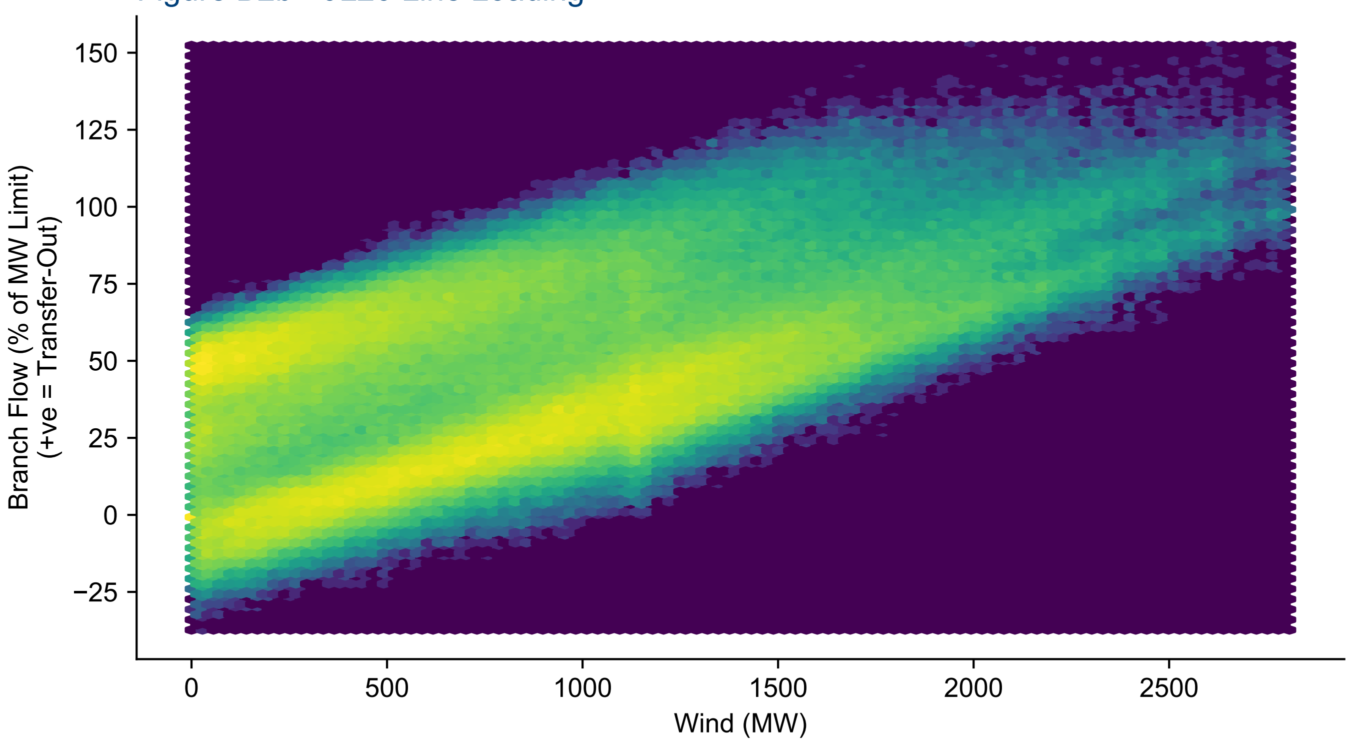


Figure B2c - 174L Line Loading

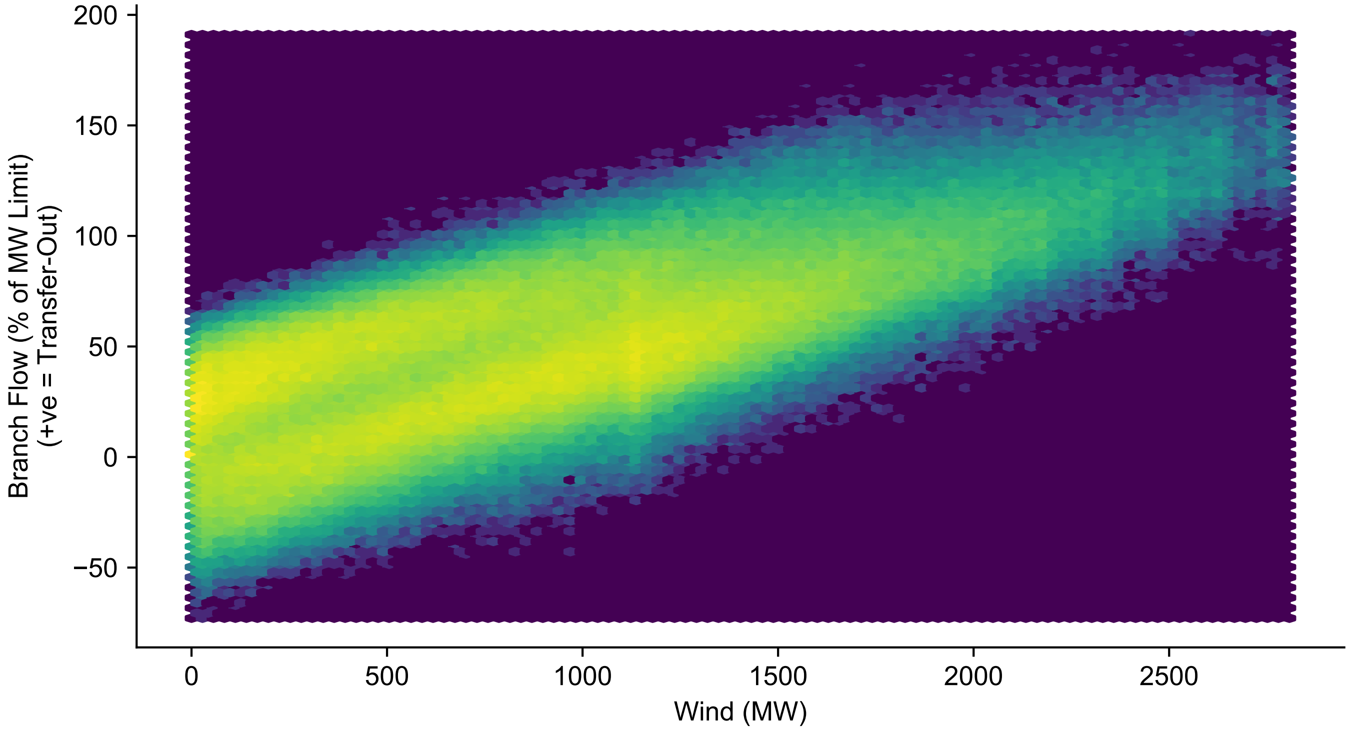


Figure B2d - 701L Line Loading

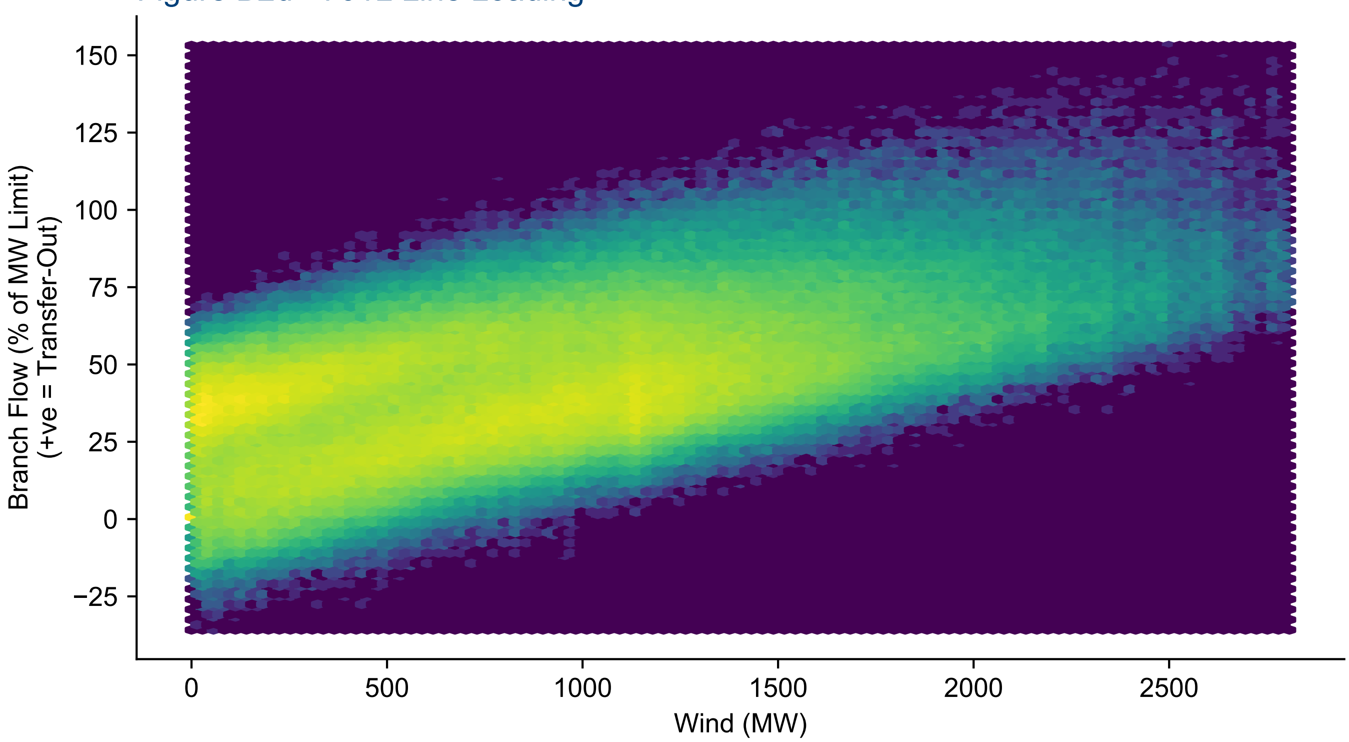


Figure B3 - Category A Congestion for Post-CETO, First Circuit

Figure B3a - 912L Line Loading

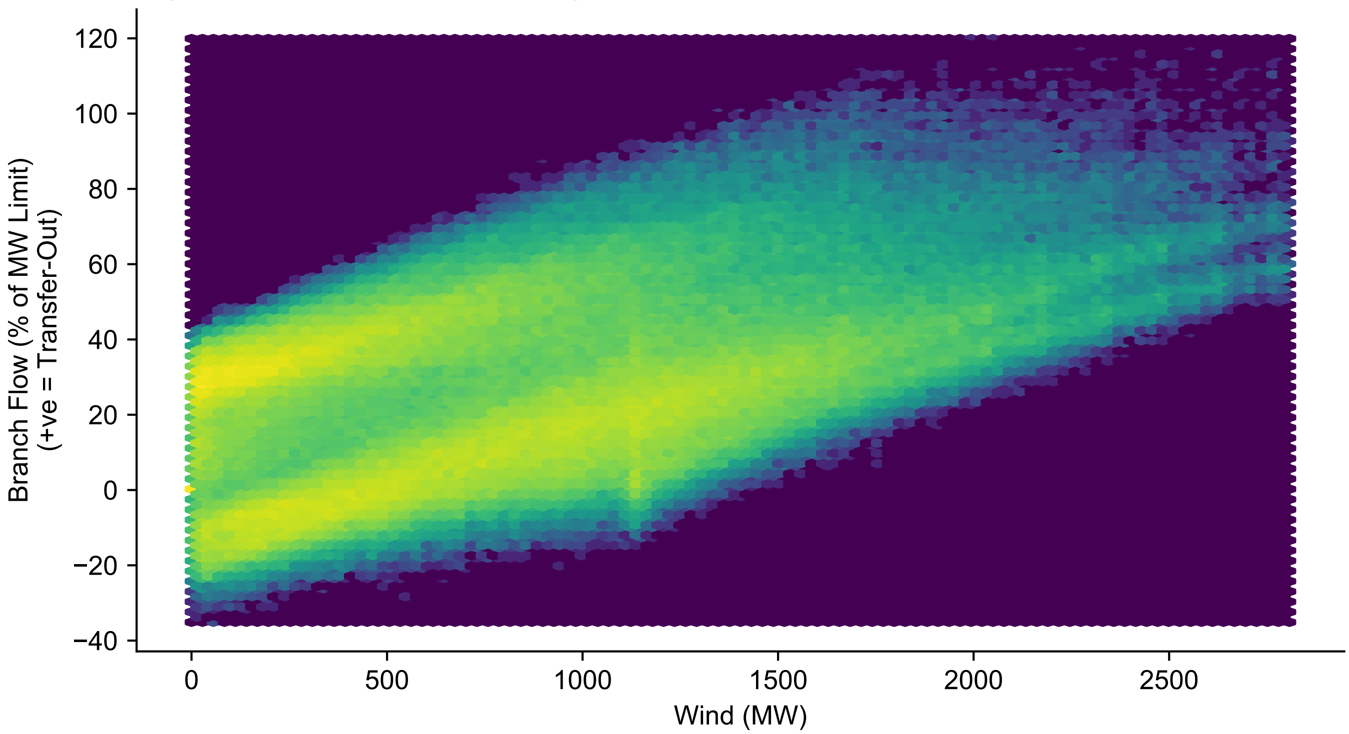


Figure B3b - 9L20 Line Loading

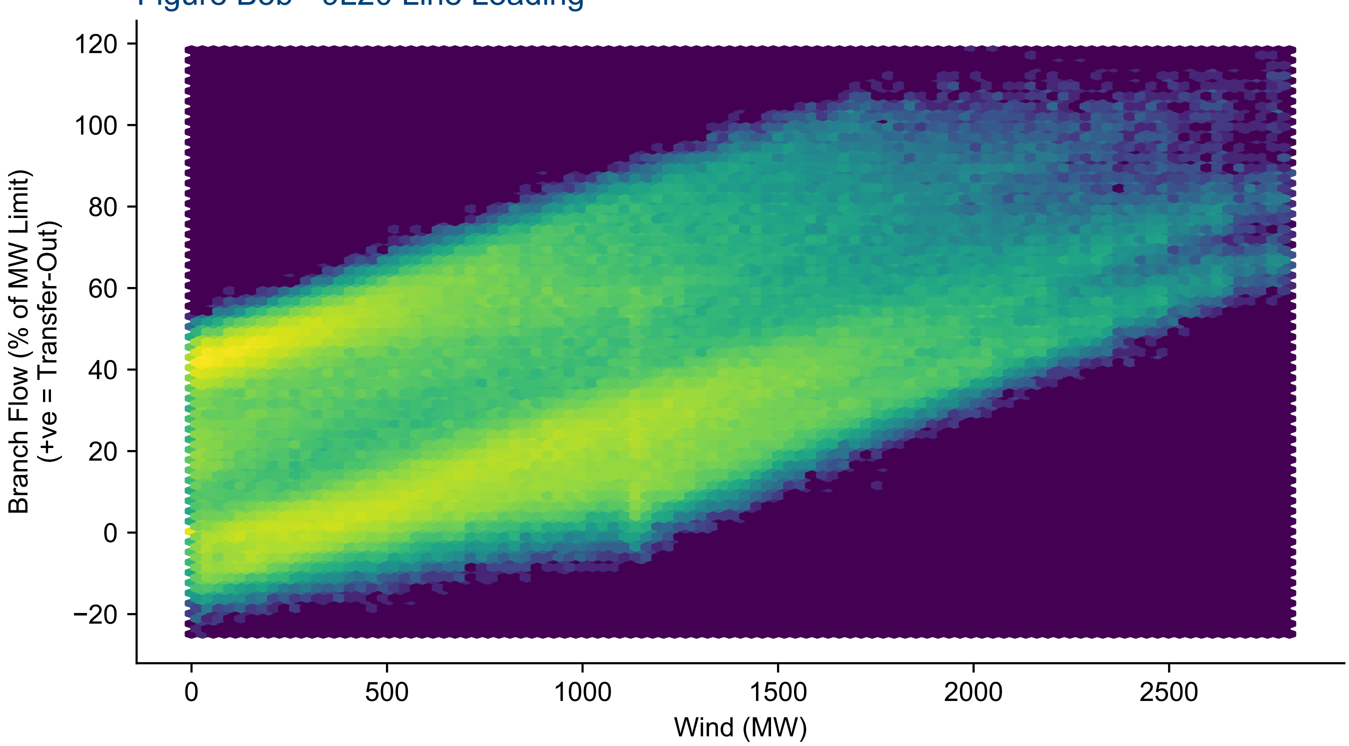


Figure B3c - 174L Line Loading

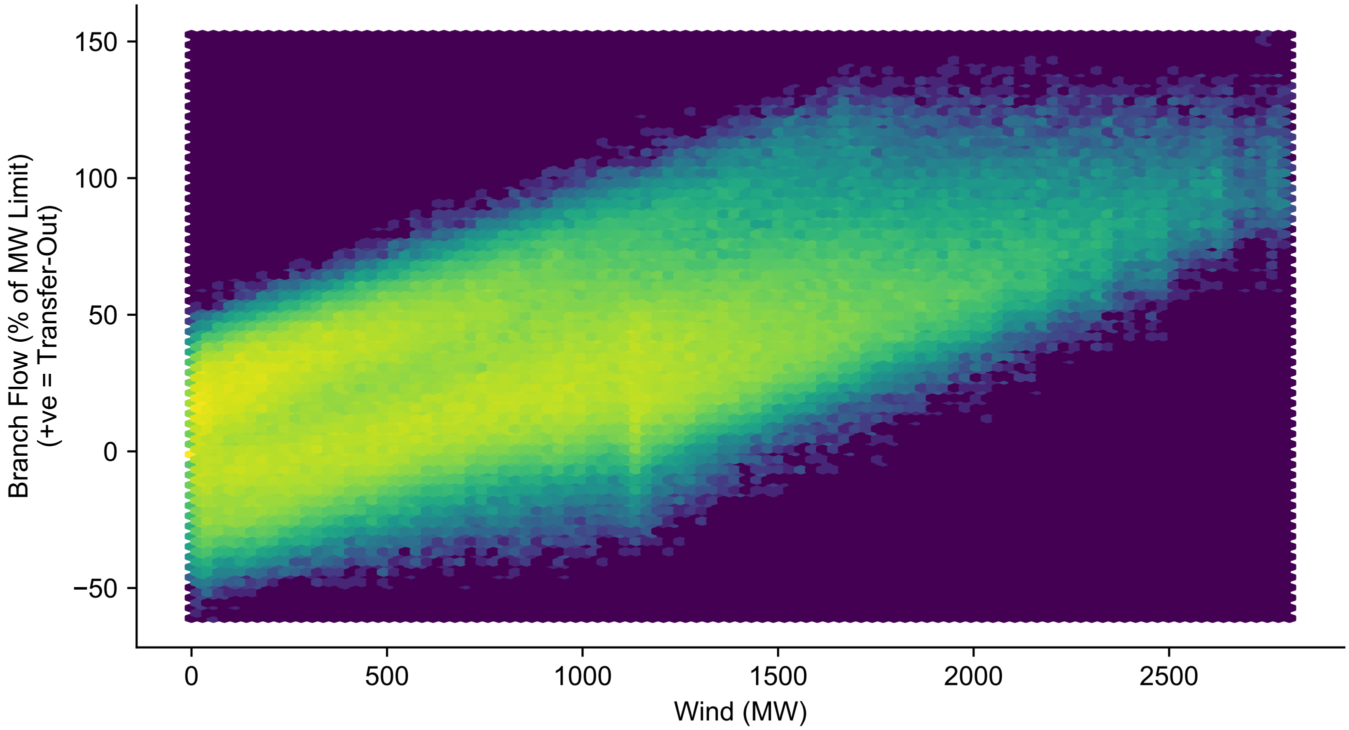


Figure B3d - 701L Line Loading

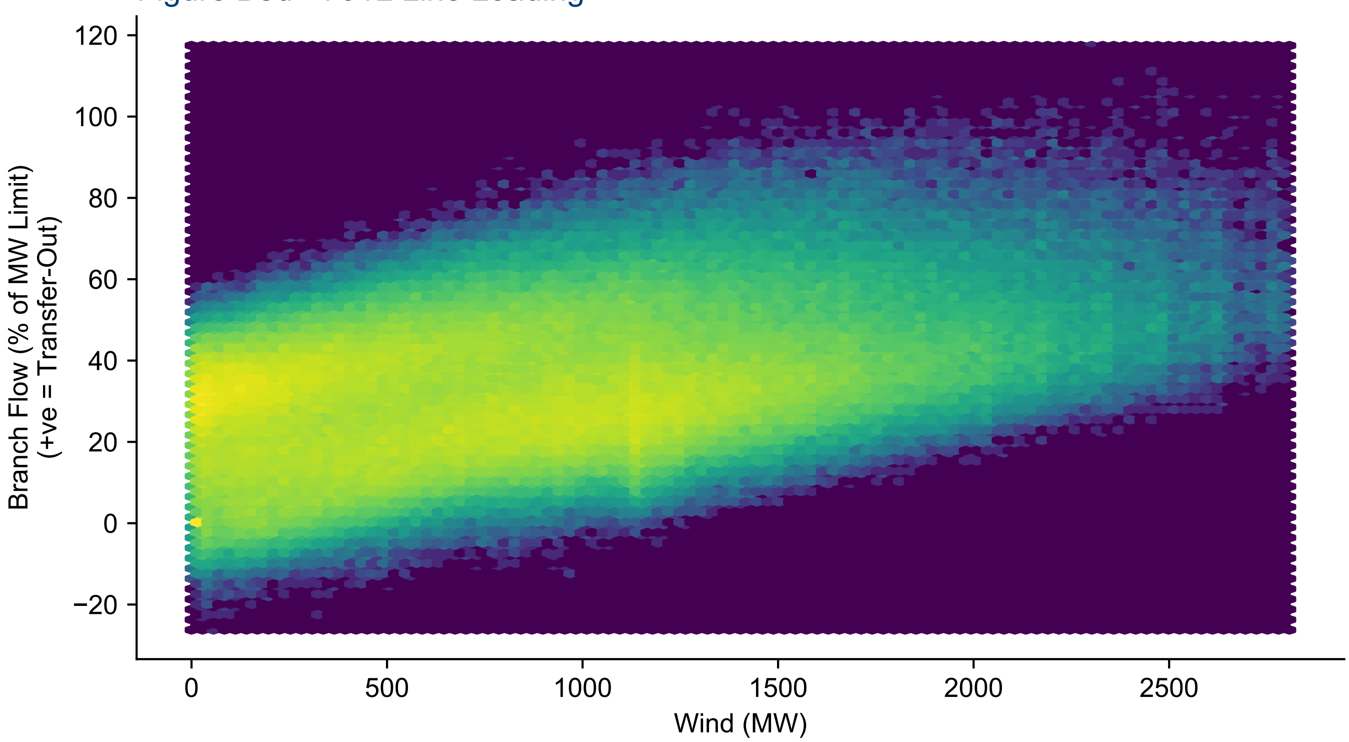


Figure B4 - Category A-MSSC Congestion for Post-CETO, First Circuit

Figure B4a - 912L Line Loading

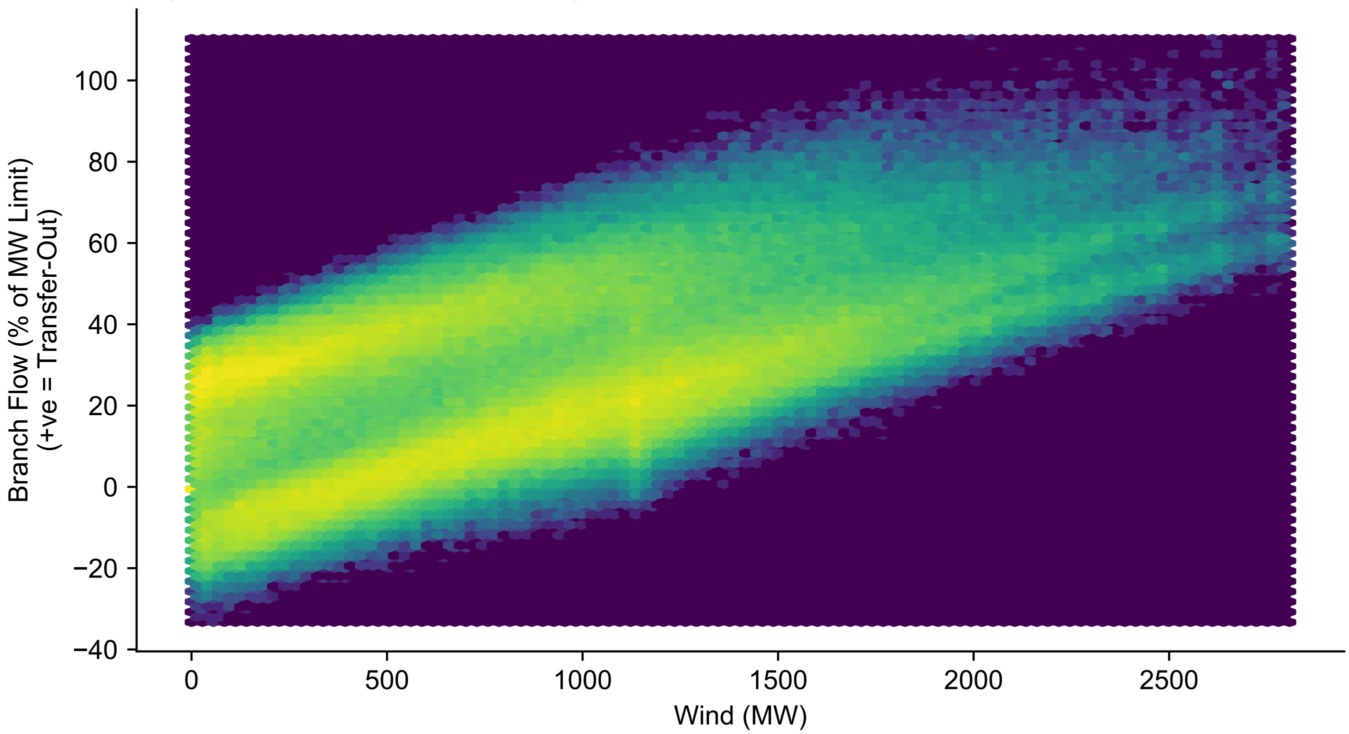


Figure B4b - 9L20 Line Loading

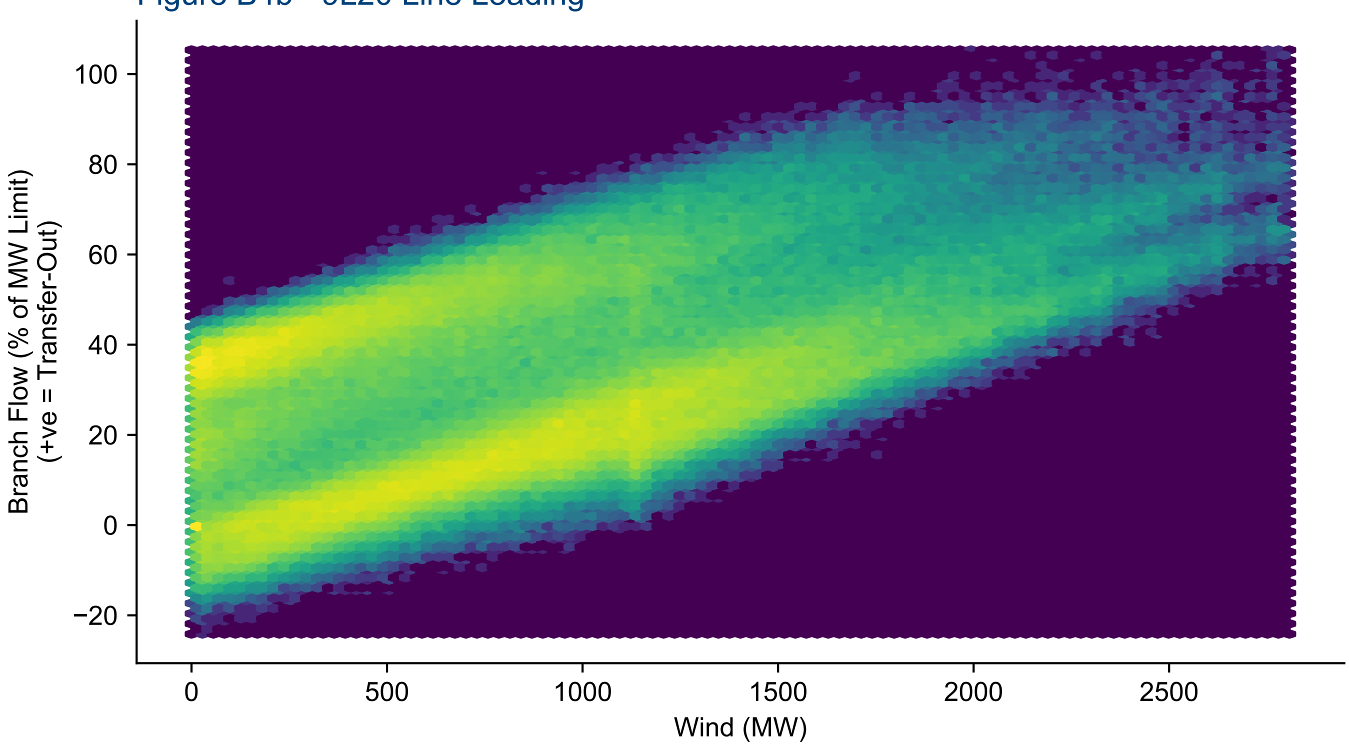


Figure B4c - 174L Line Loading

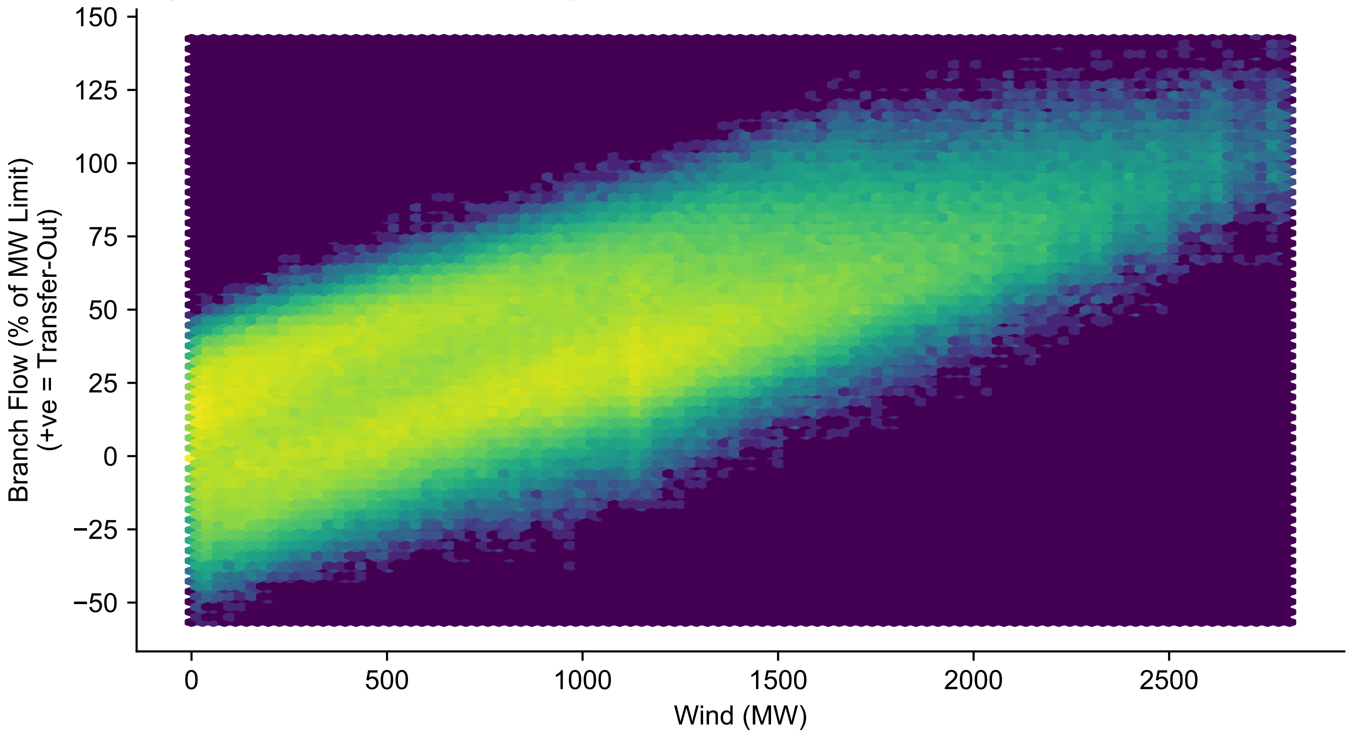


Figure B4d - 701L Line Loading